Columbia Gas of Pennsylvania
A NiSource Company

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April 1, 2015

VIA E-FILING

Rosemary Chiavetta
Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120-3265

RE: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. Docket No. R-2015-2469665

Dear Secretary Chiavetta:

Enclosed for filing on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia") is Supplement No. 230 to Tariff Gas of Pa. PUC No. 9 ("Supplement No. 230"), issued April 1, 2015, with a proposed effective date of October 1, 2015. Supplement No. 230 is filed pursuant to Section 1307(f) of the Public Utility Code to provide for annual adjustment and reconciliation of Columbia's gas cost recovery rates. Supplement No. 230 proposes a decrease in gas cost recovery rates of $0.14050/Therm.

Also enclosed is Columbia's Direct Testimony and related exhibits as required by the Commission's regulations. Columbia has provided an explanation of over/under collections for the twelve month reconciliation period ending January 31, 2015, which is attached as Exhibit 1-F, Schedule 2, to Statement No. 2.

Copies of the enclosed filing have been served on the parties designated on this letter.

Please direct any inquiry with regard to this filing to me at (724.416.6370) or to Columbia's Counsel, Theodore J. Gallagher (724.416.6355) both at the address written above, or to Columbia's outside counsel, Michael W. Hassell, Post & Schell P.C., 17 North Second Street, 12th Floor, Harrisburg, Pennsylvania 17101, (717.612.6029).

Sincerely,

Nancy J. D. Krajovic

Nancy J. D. Krajovic

Enclosure

cc: Mark R. Kempic
Theodore J. Gallagher, Esquire
Andrew S. Tubbs, Esquire
Michael W. Hassell, Esquire
Todd Stewart, Esquire
Bureau of Investigation and Enforcement
Office of Consumer Advocate
Office of Small Business Advocate

COLUMBIA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
vs.	)	Docket No. R-2015- 2469665
	)	
Columbia Gas of Pennsylvania, Inc. (Purchased Gas Cost - 66 Pa. C.S. § 1307(f))	)	

DIRECT TESTIMONY OF
HENRY A. CATRON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2015

Q. Please state your name and business address.

A. Henry A. Catron, 290 W Nationwide Blvd, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am the Director of Supply & Capacity Planning in NiSource Corporate Services Company's Commercial Operations ("CO") group, providing gas supply planning and demand forecasting services to Columbia Gas of Pennsylvania, Inc. ("Columbia").

Q. Please describe your primary supply related responsibilities.

A. I am responsible for activities related to gas supply and capacity planning, forecasting daily and design day demand and determining the optimum use of Columbia's supply/capacity assets. This includes all direct gas supply management functions including development of detailed long-range plans, short-term operational planning and strategies and day to day operation to ensure that adequate, reliable gas supplies are available, obtained and delivered in a least cost manner, consistent with our obligation to provide safe and reliable service.

Q. Please describe your professional experience along with your educational background.

A. I have been employed by NiSource or its affiliates in the gas supply area since 1989. From 1989 to 1991 I was Manager, Gas Estimates where I coordinated demand forecasting process for gas distribution affiliates within the Columbia family of gas distribution companies. From 1991 until 2000 I was Manager, Operational Planning, where I was responsible for short-term operational planning, peak day forecasting and daily supply operations. From 2000 to 2010 I was Manager, Economic Analysis, and was responsible for long-term and short-term supply planning activities. From 2010 to 2013, I was Manager, Planning and Demand Forecasting, and in May 2013 I was promoted to my current position.

From 1981 to 1989 I was employed by Illinois Power Company in various positions, including Engineer, Gas Engineer, Planning Engineer, Short Term Planning Engineer, and Assistant Gas Distribution Superintendent. In these positions I was responsible for facility planning, gas and electric strategic planning, monthly supply and storage planning and daily activities of construction crews.

I attended the University of Kentucky in Lexington, Kentucky and received a Bachelor of Science Degree in Civil Engineering in 1981.

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

A. The purpose of my testimony is to: (1) explain Columbia's gas purchasing and procurement strategies to acquire the least cost reliable gas supplies to serve its customers; (2) describe the interstate pipeline services and capacity Columbia utilizes in its least cost purchasing plan and how this capacity compares to Columbia's policy regarding its portfolio design; (3) describe the gas supply related activities pertaining to Columbia's Customer CHOICE℠ program; (4) explain the status of Columbia's Hedging Program; (5) discuss the results of Columbia's Report

Supporting Capacity for Contract Years 2015-16 through 2018-19 and (6) discuss Columbia's successful Unified Sharing Mechanism ("USM") for sharing net proceeds from capacity releases and off-system sales.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit 1-D-1 provides detail about Columbia's gas supply contracts and related negotiations. Exhibit 1-D-2 is a statement that none of Columbia's direct producer wellhead purchase agreements contain any take-or-pay or minimum bill provisions. Exhibit 1-D-3 is a listing of Columbia's capacity contracts providing maximum daily quantities. Exhibit 2 is a listing of contracts or offers regarding historic and projected sources of gas supply. Exhibit 3 is a listing of proceedings before FERC in which Columbia had some form of participation during the last year. Exhibit 4 is a listing of actual supply and requirements data from 2014 and projected requirements for calendar years 2015-2017. Exhibit 4-A is an explanation of the variance between present and prior estimated supply and sales volumes for calendar year 2015. Exhibit 4-B is an explanation of the variance between actual and estimated sales volumes for calendar year 2014. Exhibit 5 is a statement of Columbia's fuel procurement strategy. Exhibit 6 is a statement of Columbia's off-system sales of natural gas and release of upstream transportation capacity. Exhibit 8-A relates to the cost of affiliated gas, transportation or storage as compared to the average market price of other gas, transportation or storage.

Exhibit 8-B relates to estimates of gas availability, transportation and storage capacity. Exhibit 8-C is a statement discussing Columbia's efforts to obtain gas supply and transportation and storage capacity from non-affiliated interests. Exhibit 8-D explains that Columbia's purchases of gas supplies, transportation or storage capacities from affiliated interests are consistent with Columbia's least cost procurement policy. Exhibit 8-E states that Columbia has not withheld from the market any gas volumes or transportation or storage capacity during the twelve months ended January 31, 2015. Exhibit 10 is a schematic system map showing pipeline connections, supply points and storage locations serving Columbia. Exhibit 12 is a schedule of consecutive three-day peak day data by customer class for the last five years. Exhibit 13 is a copy of Columbia's 2014 Design Day Demand Forecast. Exhibit 14 is a historical and projected listing of peak period priority one customer demand. Exhibit 15 is Columbia's Report Supporting Capacity for Contract Years 2015-16 through 2018-19.

Exhibit HAC-1, attached hereto, shows peak day and annual entitlements, for contract year 2015-16, under Columbia's firm capacity contracts with Columbia Gas Transmission, LLC ("Columbia Transmission"), Dominion Transmission, Inc. ("DTI"), Equitrans, L.P. ("Equitrans"), National Fuel Gas Supply Corporation ("National Fuel"), Tennessee Gas Pipeline Company, LLC ("Tennessee") and Texas Eastern Transmission, LP ("Texas Eastern"). HAC-1 also lists upstream firm pipeline capacity utilized to deliver supplies to Columbia Transmission, namely

Columbia Gulf Transmission, LLC ("Columbia Gulf"), Tennessee and Texas Eastern.

Q. What are Columbia's projected gas sales in the 12 months ending September 30, 2016, which is the Application Period for gas costs under § 1307(f) of the Public Utility Code?

A. As shown in Exhibit 1-A, Schedule 1, Sheet 1 of 2, line 3, Columbia's projected sales for the 12 months ending September 30, 2016, total 332,649,766 Therms.

Q. Does this amount include sales by Natural Gas Suppliers ("NGS") under Columbia's Customer CHOICE[SM] program?

A. No, only projected sales by Columbia are included in Exhibit 1-A, line 3.

Q. Please describe the procedures that Columbia uses to estimate customer requirements.

A. For purposes of the estimates used in this Section 1307(f) filing, Columbia has estimated its customers' seasonal requirements by customer class, assuming 20-year normal weather and expected market conditions. Columbia combines base load and temperature sensitive demand to determine monthly residential and commercial customer requirements. The monthly gas space heating demand for residential and commercial customers is derived from United States Weather Bureau temperature data for those weather stations pertinent to Columbia's operations, applied to the projected heating load usage factors. Columbia utilizes a grass roots survey of industrial customers to estimate industrial demand.

Columbia then estimates customer participation levels under its various transportation programs. These participation levels are deducted from Columbia's demand estimates to establish projected sales levels.

Q. Does Columbia determine customer demand for conditions other than normal weather?

A. Yes. As more fully described in Exhibit 5, for supply planning purposes Columbia determines customer demand under various weather scenarios. Columbia determines customer demand under a colder-than-normal weather scenario to plan its gas supply and capacity portfolio to ensure that it is adequate to meet increased customer demand. Columbia also determines customer demand under a warmer-than-normal weather scenario to plan the flexibility needed in its supply and capacity portfolio to meet reduced customer demand at least cost.

Q. Please describe the conditions Columbia utilizes to define colder-than-normal and warmer-than-normal customer demand.

A. For colder-than-normal demand, Columbia incorporates increased seasonal heating degree-days based upon a 10 percent probability of a colder-than-normal occurrence, a seasonal peak day at design temperature and late winter design cold days. For warmer-than-normal demand, Columbia reduces winter season normal heating degree-days based upon a 10 percent probability of a warmer-than-normal occurrence. The 10 percent probability level for the colder-than-normal weather scenario means that there is a 10 percent risk that the winter will have more heating degree-days compared to the normal scenario. Conversely, the 10 percent probability for the warmer-than-normal weather scenario means that there is a 10 percent risk that the winter will have less heating degree-days compared to the normal scenario. Columbia utilizes normal weather heating degree-days for the summer season in all demand determinations described herein. On a weighted average basis, for Columbia's service territory, approximately 82 percent of the annual heating degree-days for a normal year occur in the five-month winter season (November - March) and 18 percent in the seven-month summer season (April – October).

Q. Please describe the late winter design cold days and their importance.

A. Columbia utilizes late winter design cold days to test the adequacy of its supply portfolio on cold days late in the winter season, after the planned occurrence of the seasonal design day. As storage supplies are withdrawn, the deliverability of natural gas storage fields decline. Pipeline tariffs recognize this decline and reduce withdrawal entitlements in accordance with the volumes remaining in storage. Due to Columbia's heavy reliance upon storage, Columbia utilizes the late winter design cold days to properly manage storage withdrawals and assure that its capacity portfolio can reliably meet customer demand on such cold late winter days under all planning scenarios, including the colder-than-normal weather scenario.

Q. Please describe the conditions Columbia utilizes to estimate its design day demand.

A. Columbia's design day demand forecast (peak day forecast) is based upon the following conditions and considerations: (1) the "design" conditions of (a) current day design temperature, (b) prior day design temperature, (c) current day design wind speed and (d) occurrence of the design peak day on a weekday; (2) an estimate of the number of customers to be served each January for the term of the forecast; (3) an estimate of the price of gas for each November for the term of the forecast; and (4) the assumption that normal temperatures will be experienced in each December and January for the term of the forecast because these are the two months when Columbia's design conditions are most likely to occur. All of the above factors influence customer demand on Columbia's system on the current day.

The current and prior day design temperatures were developed utilizing all available historic weather data ending with the winter of 2007-08. Columbia updates these design temperatures every five to ten years. The current day design temperature is determined by utilizing a Gumbel Distribution of the annual minimum daily mean temperatures, with a 1 in 15 or 6.67 percent risk factor. That is, the probability is 6.67 percent that any given winter will have one or more days with a mean daily temperature equal to or colder than the current day design temperature.

The prior day design temperature is determined from the mean temperature difference between historical "cold days" and their associated prior days. "Cold days" are defined as those that are no warmer than the current design day temperature plus 5 degrees Fahrenheit.

The design wind speed is based on an analysis of wind activity for the 1990-91 through 2007-08 winter seasons. Columbia updates this wind speed analysis every five to ten years. This analysis determines the average daily wind speed on days that are no warmer than the current design day temperature plus 15 degrees Fahrenheit.

Columbia then utilizes a multiple variable, linear regression analysis of (1) historic daily demand, temperature and wind speed data to determine the design actual daily demand estimate for the most recent year; and (2) a second multiple variable, linear regression analysis of the estimated historic design actuals, January customer counts (historic and forecast), December/January degree days (actual and normal) and retail gas prices (historic and forecast) to develop its design day forecast.

Q. Does Columbia plan for a date of occurrence of a peak day?

A. Yes, Columbia determines the latest date within a winter season, with a 10 percent probability that a current day design temperature or colder may occur in Columbia's service area. Columbia analyzes the historical dates of occurrence of peak day or colder temperatures to determine this date. Columbia's current planned latest date of peak day occurrence is January 25th.

Q. Does Columbia plan for dates where storage deliverability can be reduced?

A. Yes, for reliability purposes, Columbia determines the lowest temperatures at which firm customer demand can be satisfied immediately after a reduction in storage deliverability. Once Columbia determines these temperatures, the Company then determines the latest dates, with a 10 percent risk, that these temperatures may occur.

Q. What is the importance of these dates?

A. As noted earlier, the deliverability of natural gas storage fields decline as storage supplies are withdrawn. Under the interstate pipeline storage service tariffs utilized by Columbia, the right to withdraw storage volumes is reduced when specific storage inventory levels are reached. These ratcheted reductions in storage withdrawal entitlements occur in steps. Under the FSS tariff of Columbia Transmission, the first step, which reduces storage withdrawal entitlements to 80% of the maximum, is reached when remaining storage inventory is less than 30% of the seasonal contract quantity. Under Columbia's FSS contract with Columbia Transmission, this first reduction in deliverability reduces deliverability by 91,375 Dth/day, to 365,501 Dth/day. Columbia determines the temperature which has a forecast firm demand equal to the design peak day demand reduced by 91,375 Dth/day. For example, for contract year 2017-18 the design peak day demand of 642,500 Dth/day is reduced by 91,375 Dth to approximately 551,100 Dth to reflect the first storage ratchet. Columbia determines the temperature which has a forecast firm demand equal to 551,100 and determines the latest date beyond which there is a 10% risk that this temperature will occur. Columbia then manages its FSS storage inventory such that a minimum of 30% remains on this date. Two additional steps reduce withdrawal entitlements to 65% and 50% of maximum. These steps occur when storage inventories fall below 20% and 10%, respectively. Columbia must manage its storage inventories throughout the winter season to prevent a premature storage deliverability reduction. Such a premature reduction could leave Columbia with insufficient firm supplies to satisfy the demand of firm customers on cold days late in the winter.

Q. Please describe Columbia's pipeline services listed on Exhibit HAC-1.

A. As noted on Exhibit HAC-1, for contract year 2015-16, Columbia will receive firm pipeline services from seven interstate pipeline companies, namely, Columbia Transmission, Columbia Gulf, DTI, Equitrans, National Fuel, Tennessee and Texas Eastern. Columbia receives firm transportation services from Columbia Transmission, Columbia Gulf, National Fuel, Tennessee and Texas Eastern. Columbia will receive storage and related firm transportation services from Columbia Transmission, DTI and Equitrans.

Q. Please describe Columbia's pipeline service from its affiliated pipeline, Columbia Transmission.

A. Columbia contracts for three primary firm services from Columbia Transmission: Firm Transportation Service ("FTS"), Firm Storage Service ("FSS") and Storage Service Transportation ("SST"). The FTS capacity provides for the firm transportation of flowing gas supplies delivered by Columbia Transmission, either from Appalachian receipt points or interconnects with upstream pipelines, to Columbia's city gates or storage. The FSS capacity provides daily injection and withdrawal capacity into or out of storage, along with firm peak day deliverability and seasonal storage capacity. The primary utilization of the SST capacity is providing firm transportation of storage volumes from Columbia Transmission's storage fields to Columbia's city gates. A secondary use of SST is transporting flowing gas supplies, in excess of Columbia's FTS capacity level, to fill storage during the summer. The use of FSS in conjunction with SST provides Columbia with its primary daily no-notice balancing service.

Q. Please describe the importance of the Columbia Transmission capacity to Columbia.

A. Natural Gas Distribution Companies ("NGDCs"), such as Columbia, are fully responsible for the delivery of supplies from producers, marketers and other supply aggregators, to fulfill 100 percent of the supply requirements of sales and Choice customers. For the majority of Columbia's markets, Columbia Transmission provides the only physical pipeline connection to facilitate such service. Thus, the use of Columbia Transmission's facilities is critical to Columbia's ability to provide reliable, economic service to its customers. Further, NGDCs are responsible for balancing all deliveries to their city gates on a daily basis. Columbia's widespread, discrete service territories, large number of city gates and highly temperature sensitive customer requirements create unique daily balancing challenges. In order for Columbia to operate its purchasing program in the most cost effective manner, it must be able to balance all scheduled deliveries and demand at all city gates on a daily basis.

Because the vast majority of Columbia's market areas are served only by facilities owned by Columbia Transmission, Columbia is able to utilize its FSS capacity to balance deliveries and demand to all but a handful of its city gates. Columbia's widespread, discrete service areas and large number of city gates make it uneconomic to construct interconnections between Columbia and other pipelines. As noted on Exhibit HAC-1, Columbia Transmission delivers 88 percent of Columbia's design day supply. As such, Columbia must continue to rely primarily upon its interconnects with Columbia Transmission to deliver the majority of supplies necessary and meet the requirements of its markets.

Q. Please describe Columbia's pipeline service from its affiliated pipeline, Columbia Gulf.

A. Columbia contracts for firm transportation services from Columbia Gulf under Columbia Gulf's FTS-1 Rate Schedule. The FTS-1 service provides firm transportation from the Rayne, Louisiana compressor station to the Leach, Kentucky interconnection between Columbia Gulf and Columbia Transmission.

Q. Did Columbia experience any changes to its firm contracts or contract levels with affiliated capacity suppliers during the past year?

A. Yes. As explained in Exhibit 5, Sheets 11 and 12, Columbia extended two FTS agreements with Columbia Transmission.

Q. Does Columbia anticipate any changes to its contract levels with affiliated capacity suppliers during the coming year?

A. No, Columbia does not anticipate any changes to its contract levels with affiliated capacity suppliers during the coming year.

Q. Please describe the pipeline services Columbia receives from its non-affiliated pipeline service providers.

A. Columbia has three firm transportation contracts and two storage contracts with DTI. The first transportation contract, under rate schedule FTNN-GSS for 6,000 Dth per day, is utilized to transport storage supplies from DTI's storage fields to Columbia's city gates. Storage supplies are also transported to Columbia's city gates via a second transportation contract under rate schedule FT. This contract has a quantity of 3,000 Dth per day from November through March of each year, and 2,000 Dth per day from April through October of each year. The associated storage contract with DTI provides it with 9,000 Dth/day of peak day deliverability and approximately 941 MDth of seasonal supply. Columbia utilizes these DTI contracts to provide supplies to its customers in Beaver County through its Darlington interconnect and in Cranberry Township through its Warrendale interconnect.

Columbia's second storage contract and related transportation contract on DTI are utilized to meet the demand and balancing requirements in the State

College market. This storage contract provides for a daily withdrawal of 4,800 Dth per day and a seasonal quantity of 240,000 Dth/day. The associated Rate Schedule FTNN transportation contract provides for the delivery of 4,800 Dth per day from storage to the State College market.

Columbia also contracts for firm transportation and storage service with Equitrans. The storage service provides peak day deliverability of 14,348 Dth and 1,500,000 Dth of seasonal capacity. The firm transportation service has a winter season Transportation Quantity ("TQ") of 14,348 Dth/day and a summer season TQ of 7,500 Dth/day.

Columbia utilizes the Equitrans storage service, the associated 14,348 Dth/day of the winter season FTS TQ, and the DTI storage service and associated 4,800 Dth/day FTNN transportation contract, discussed above, to provide service to General Distribution Service ("GDS") customers under Columbia's Elective Balancing Service ("EBS") Option 1 and peak day service to its Sales and CHOICE℠ customers. I will discuss EBS in greater detail later in my testimony.

Columbia currently contracts for firm transportation service with Tennessee totaling 36,100 Dth/day. A total of approximately 19,300 Dth/day is required to serve the design peak day firm customer demand in Columbia markets directly connected to Tennessee, while approximately 4,300 Dth/day is delivered to Columbia's National Fuel capacity and 12,500 Dth/day is delivered to Columbia Transmission, as an upstream supply, to meet design day demand in other

Columbia markets served by National Fuel and Columbia Transmission. On days when the 19,300 Dth/day delivered directly to Columbia cannot be absorbed by those markets, Columbia can divert that supply to Tennessee interconnects with Columbia Transmission for injection into storage or delivery to other Columbia markets served by Columbia Transmission.

Columbia contracts for long-haul firm transportation service under two rate schedules with Texas Eastern, FT-1 and CDS, totaling 22,335 Dth/day. A total of 19,253 Dth/day is required to serve the design peak day firm customer demand in Columbia markets directly connected to Texas Eastern while 3,082 Dth/day must be delivered to Columbia Transmission, as an upstream supply, to meet design day demand in Columbia markets served by Columbia Transmission. Similar to operations on Tennessee, on days when the 19,253 Dth/day delivered directly to Columbia cannot be absorbed by those markets, Columbia can divert that supply to secondary delivery points off Texas Eastern or to Texas Eastern interconnects with Columbia Transmission for injection into storage or delivery to other Columbia markets served by Columbia Transmission. Columbia also contracts for 10,000 Dth/day of winter season, market-area firm backhaul transportation capacity. Columbia utilizes this capacity to satisfy cold weather requirements behind the city gates connected to Texas Eastern.

Columbia contracts for 4,281 Dth/day of city gate capacity under the FTS rate schedule of National Fuel. This capacity is utilized to serve Columbia's Warren market area. As noted earlier, Columbia utilizes portions of its Tennessee contracts to provide supply to the National Fuel capacity. Columbia can divert the Tennessee supplies when not needed to serve National Fuel fed markets for delivery to other Columbia markets served by Columbia Transmission or injection into storage.

Q. Did Columbia experience any changes to its capacity contracts with non-affiliated pipeline suppliers since last year's 1307(f) filing?

A. There were no changes other than the reduction in Equitrans storage and transportation quantitates and the addition of DTI storage and transportation contracts. These changes, which were discussed in last year's 1307(f) filing, became effective April 1, 2014.

Q. Please summarize Columbia's New and Renewed Capacity process.

A. Each of Columbia's contracts for pipeline storage and firm transportation service contain specific provisions detailing termination dates, as well as notification dates, wherein Columbia must notify the respective interstate pipeline if it decides to renew the capacity under current contract terms beyond the contract termination date. Approximately 6-9 months prior to this notification date, Columbia determines whether this capacity or its equivalent is required to serve its residential and small commercial customers. Upon determining that the capacity is required, Columbia then determines whether this capacity is also required for system balancing or Supplier of Last Resort ("SOLR") services.

For capacity that is not required for balancing or SOLR services, Columbia prepares a Request for Proposal ("RFP") and submits the RFP to all NGSs who are licensed to conduct business on Columbia's system. This RFP defines the delivery points required by Columbia to receive gas supplies, as well as a general outline of the daily delivery volumes by point of delivery. The qualified NGSs determine if they have a desire to deliver gas supplies to Columbia at these points in the manner required by Columbia to serve its markets utilizing firm primary point capacity. If an NGS determines it has the desire and ability, then it can submit an offer under the RFP. Once received, Columbia will evaluate all offers to determine whether they meet the requirements of the RFP and, if appropriate, compare such offers against other options available to Columbia. If the offer complies with the RFP and is better than other options available to Columbia, the successful NGS and Columbia will enter into an agreement defining the delivery details required to serve the relevant market. This process of offering and accepting an offer from an NGS, along with completion of the delivery agreement, must be completed in a timely manner in order to allow Columbia to terminate the capacity that is the subject of the RFP. In the event that no offer is received under the RFP, Columbia proceeds to either extend the contract under existing terms and rollover rights, if available, or renegotiate the contract.

Q. Did Columbia offer NGSs operating on its system an opportunity during the past year to provide new or replacement capacity under its Acquisition Process for New and Renewed Contracts?

A. Yes, Columbia provided NGSs opportunities during the past year to provide offers of replacement capacity.

Q. Please describe the capacity for which Columbia requested offers from NGSs to replace.

A. Columbia requested replacement capacity offers on a total of 7,500 Dth of M-3 firm transportation capacity provided by Texas Eastern, and 4,304 Dth of firm transportation capacity on National Fuel.

Q. Did Columbia receive any offers of replacement capacity from an NGS?

A. No.

Q. Are these contracts for which Columbia requested replacement offers from NGSs required by Columbia?

A. Yes, they are.

Q. Please describe the actions taken by Columbia to renew these contracts.

A. Columbia exercised its annual rollover right and retained the capacity under existing contractual provisions for the Texas Eastern M-3 and the National Fuel contracts.

Q. Is the firm capacity listed on Exhibit HAC-1 required to meet Columbia's projected design peak day firm requirements?

A. Yes.

Q. Is the firm capacity listed on Exhibit HAC-1 consistent with Columbia's policy regarding the level and mix of its supply/capacity portfolio?

A. Yes. A reconciliation of Columbia's firm peak day capacity entitlement level with Columbia's future years' firm design peak day demand per Columbia's 2014 Design Day Forecast, as provided in Exhibit 13, shows that Columbia's current peak day capacity level is within the guidelines of its portfolio design policy. This is shown in Exhibit HAC-2.

Q. Was Columbia active in any Federal Energy Regulatory Commission ("FERC") proceedings during the last year?

A. Yes, as shown in Exhibit No. 3, either directly, as part of the Columbia Distribution Companies, or through its memberships in industry trade associations like the American Gas Association ("AGA"), Columbia was active at the FERC in regulatory proceedings, rulemakings and policy formulation that had the potential to impact services and/or costs to Columbia and its customers.

Q. Generally, how has Columbia represented the interests of its customers by participating in each of the listed proceedings?

A. First, Columbia reviews all relevant FERC notices of rate, certificate and rulemaking proceedings through a monitoring network on FERC's website and through AGA's notifications. In addition, Columbia maintains various contacts in Washington, D.C., who from time to time forward federal regulatory information that may be of interest. Further, Columbia, as a customer of various pipelines, receives notices of rate and proposed tariff changes as filed. Finally, Columbia makes every effort to conduct various forms of informal communication with its pipeline suppliers, peer customers of those pipelines and respective interested state agencies to keep apprised of upcoming proposals, expected tariff filings and any other federally regulated activities.

Second, a preliminary analysis of notices and filings is completed by Columbia's Supply and Optimization personnel for discussion with Legal, Regulatory and Commercial Operations personnel. Based on those discussions, a determination is made whether to intervene. If a determination is made to intervene, then intervention points are developed. A decision to become an active participant in a proceeding protects Columbia's right to address the elements of a filing that are significant to Columbia. Being an active participant ensures that Columbia is advised of all pre-hearing, technical and settlement conferences and hearings convened in a case, as well as input through comments and intervention of others.

Analysis of those filings in which Columbia has intervened is conducted on an ongoing basis. The potential impact of rate and policy changes is determined. From these analyses, Columbia reasonably formulates positions that best represent the interests of Columbia and its customers, and recommends a level of involvement necessary to advocate those positions. Columbia pursues those positions through the legal process, by filing comments and/or testimony on its own when appropriate, through trade or customer groups, through participation in technical conferences and/or through negotiations within the settlement process.

As indicated earlier, Columbia is also a member of the AGA, a natural gas industry trade group that participates actively in select proceedings on behalf of its local distribution company members. In particular, Columbia is actively involved in the AGA FERC Regulatory Committee, which addresses industry issues such as those listed in Exhibit No. 3. Also, Columbia is an active participant in various NAESB subcommittees which have been called upon by FERC to develop standards in areas such as standards of conduct, nomination timelines, creditworthiness, gas quality reporting, improved coordination between the gas and electric industries, capacity release and the NAESB Base Gas Purchase and Sales Contract.

As demonstrated by Exhibit No. 3, Columbia was an active party to scores of FERC proceedings in calendar year 2014 and has been similarly active in the first quarter of 2015. Many more pipeline filings and proposals that were reviewed by Columbia during that time are also listed, but Columbia only became a party in those cases where it determined that there was the potential for significant impact on it or its customers.

Q. Please summarize Columbia's FERC activities throughout the past year.

A. During 2014, Columbia paid particular attention to the impact of rate filings by pipelines that proposed adjustments to tariff rates. Columbia's activities can be summarized as follows:

- Reviewing all FERC filings by all pipelines that provide natural gas transportation services to Columbia;
- Intervening in and following all FERC dockets having potential ramifications to Columbia; and
- Participating in all major proceedings in which tariff changes and reliability issues affecting Columbia's customers were scheduled to be discussed. This included attending technical conferences and settlement conferences hosted by the FERC and the pipelines.

Gas Electric coordination that has the potential to impact Columbia and its customers is covered in detail in Exhibits 3 and 5.

Q. What are Columbia's gas purchasing objectives and strategies?

A. Columbia has a least cost objective to secure and deliver competitively priced, reliable gas supplies for its customers. Columbia is sensitive to the impact of gas costs upon its customers and balances this concern with its utility obligation to provide reliable gas supplies to its firm customers whenever they want gas service under a wide range of weather conditions.

Columbia's gas purchasing strategy is to contract for a portfolio of gas supplies and capacity that has the flexibility both to meet reliability standards and be able to take advantage of low price opportunities when available and operationally feasible.

Q. What are Columbia's gas procurement policies?

A. Columbia contracts for sufficient firm gas supplies to serve, at a minimum, the demand of its firm service customers under design weather conditions, both design day and seasonal. Firm gas supplies include storage supplies, purchases under firm gas supply contracts and firm monthly and daily gas supply purchases, delivered through firm transportation capacity and local gas supplies on a seasonal basis. Firm gas supply contracts can include both long-term and short-term contracts that provide the supplier with an incentive to deliver supplies with a high degree of reliability on a daily and seasonal basis.

In contracting for firm gas supplies, Columbia contracts for sufficient firm supplies to fill its firm transportation capacity required to serve design day firm requirements during the months of December through February. Columbia purchases these supplies during these three months to assure sufficient gas supplies are available in the event Columbia experiences colder than normal daily temperatures. During the months of March and November, Columbia reduces purchases under its term contracts and increases the level of purchases under spot gas contracts to increase flexibility and minimize gas costs for its customers.

Q. Please address Columbia's segmentation of its gas supply contracts.

A. Columbia's contracts are presently segmented into two categories; short-term and spot market. Columbia defines short-term contracts as firm gas purchase agreements with a contract length of one year or less. Spot market contracts are gas purchases made at the time of need for between one day and one month in length.

Q. How does Columbia determine prices under these contracts?

A. Prices under firm short-term contracts are typically based upon a nationally published index plus a small premium. The index and premium are established as a result of the contract negotiation process. Spot market contract prices are based on market conditions negotiated at the time of purchase.

Q. Please explain the premium Columbia pays under its short-term firm purchase contracts.

A. Columbia negotiates a nominal premium with suppliers for purchases under its short-term gas purchase agreements to assure Columbia and its customers of sufficient firm, reliable gas supplies at competitive prices, under widely varying weather and market conditions.

Q. Please describe the process Columbia follows to contract for short-term firm supplies.

A. Annually, Columbia submits a Request For Proposal ("RFP") to numerous suppliers identified as capable and willing to provide firm gas supplies to Columbia. Columbia requests proposals for supplies with varying term lengths, nomination flexibility and innovative pricing options. Upon receipt of proposals submitted in response to the RFP, Columbia evaluates the responses and begins negotiations with suppliers whose proposals provide the required supply assurances at the least cost. Negotiations continue until satisfactory agreements are reached or until an impasse is reached, after which another supplier negotiation is initiated.

Q. What were the results of your most recent RFP cycle?

A. Effective for contract year 2014-15, fifteen (15) existing term gas purchase agreements expired per the terms of the agreements. Prior to the 2014-15 winter, Columbia entered into three (3) new term gas purchase agreements.

Q. Why did Columbia enter into fewer term gas purchase agreements?

A. During the 2014-15 winter season, Columbia contracted for fewer winter term contracts than in past winter periods. Columbia modified its term purchasing strategy due to: (a) the abundance of competitively-priced, reliable shale gas supplies at locations accessible to Columbia's firm transportation primary receipt points; and (b) the ever changing flow restrictions imposed by the pipeline companies that supply its market areas. Columbia did not change its long-standing practice of filling its firm capacity during the core winter months. For the 2014-15 winter, a portion of the firm capacity, historically filled with term supplies, was instead filled with monthly and daily supply purchases as needed to serve the core market requirements and maintain adequate storage levels. This strategy allowed Columbia to potentially capture the benefit of reduced cost gas supplies, and to avoid potential penalties associated with any unforeseen pipeline imposed restrictions.

Q. You indicated earlier that Columbia must balance deliveries to all city gates. Please describe how Columbia accomplishes this task.

A. Under existing pipeline tariffs, NGDCs, such as Columbia, are required to balance supply and demand daily for all customers. Because the majority of Columbia's customers have highly temperature sensitive demand, Columbia's supply portfolio must be able to provide widely varying daily supplies in response to daily changes in temperature.

In order to provide gas supplies on a least cost basis for its customers, Columbia relies heavily upon the daily withdrawal and injection flexibility of its primary storage service provided under Columbia Transmission's FSS Rate Schedule. Columbia Transmission's FSS rate schedule provides Columbia with its primary no-notice service. Columbia also has limited no-notice service on Texas Eastern and DTI.

As noted on Exhibit HAC-1, storage service provides over 72 percent of Columbia's design peak day capacity. Storage service provides Columbia with approximately 50 percent of its normal weather, winter season supply to meet the needs of its firm customers and the vast majority of its system balancing requirements. In addition, Columbia's storage capacity enables it to provide EBS to GDS customers. Storage service contributes to Columbia's ability to provide a least cost gas supply under varying weather conditions. Columbia's storage capacity also provides mitigation of winter season price increases.

While Columbia relies heavily on its storage service to meet changing customer demand, Columbia's contracted storage services do not provide it the full swing capability it requires to meet the temperature-sensitive demand swings of its customers, particularly on warmer days during shoulder months. Therefore, Columbia incorporates the use of daily spot purchases during these periods. When warranted, Columbia implements the use of "swing" provisions included in its firm gas supply contracts that provide Columbia the opportunity to reduce flowing gas supplies on these warm days, yet permit Columbia to increase flowing volumes again once weather turns colder or to meet seasonal demand.

Q. Please elaborate on Columbia's gas procurement policies regarding swing contracts.

A. Columbia's policy regarding swing gas supplies is to contract for needed supplies on a "pay as you use them" basis. In other words, Columbia only incurs swing costs when it actually uses the swing service. Typically, the swing costs take the form of a keep whole provision wherein the supplier is kept whole for the costs it incurs when providing the swing service.

Q. Does Columbia purchase spot market gas supplies in volumes exceeding its firm transportation service ("FTS") contract level during the summer months?

A. Yes. In order for Columbia to inject sufficient gas supplies into its storage accounts, particularly its FSS account with Columbia Transmission, to meet winter season customer demand, it must purchase gas supplies in volumes exceeding its FTS capacity during the summer. These additional gas purchases are made under spot market contracts and delivered to its storage accounts using Columbia's SST capacity at secondary receipt and delivery points.

Q. Does Columbia purchase Pennsylvania production?

A. Yes, Columbia maintains a program for purchasing local Pennsylvania production. A portion of the local production is delivered directly into Columbia's distribution system. Columbia purchases a second portion at Columbia Transmission's Appalachian receipt points. Purchases made with Appalachian receipt point transportation capacity are often made at pools or aggregation points where volumes of local gas become commingled with gas supplies from other sources. Therefore, it becomes impossible to determine how much of those supplies are produced in Pennsylvania.

Q. Earlier in your testimony you mentioned Columbia's Elective Balancing Service. Please describe this service and its benefits.

A. EBS provides substantial enhancements to the balancing service Columbia had traditionally provided its GDS customers. EBS provides the following benefits:

(a) Provides GDS customers with two daily balancing options. Under Option 1, NGSs and customers have the ability to carry banks over from month to month with several service enhancements, which are discussed later in my testimony. Under Option 2, NGSs and customers choose to be cashed out monthly. A monthly cashout provides customers the opportunity to carry an intra-month bank but this bank is cashed-out at the end of each month.

(b) Under EBS Option 1 NGSs and customers are provided firm cold day and warm day Operational Flow Order ("OFO")/Operational Matching Order ("OMO") tolerances. Under cold day OFO/OMOs, NGS or customer deliveries equal to or greater than 95% of actual (OMO) or estimated (OFO) demand are considered to be in compliance with the flow orders, provided that the customer has sufficient gas in its bank. Under warm day OFO/OMOs, NGS or customer deliveries less than or equal to 102.5% of actual (OMO) or estimated (OFO) demand are considered to be in compliance with the flow order, provided that the customer has sufficient room in its bank to accept the over deliveries.

(c) Under EBS Option 1, NGS and customer access to banks is now provided on a seasonal firm basis. As long as an NGS or customer has a positive bank, they will retain firm seasonal access to that bank.

Q. Please describe Columbia's capacity release program.

A. Columbia utilizes the SENDOUT® Gas Supply Model extensively to help evaluate both short and long-term capacity release opportunities. In Columbia's evaluation of the level of capacity to release, Columbia considers the requirements of its retail customers, including storage injection requirements. The total releasable capacity is equal to the difference between Columbia's monthly firm capacity level and the firm customer requirements at the applicable fifth design day (that capacity level which Columbia has determined may be needed for recall on up to 5 days in any given month). SST capacity utilized at secondary receipt and delivery points for injection into storage is also factored into the analysis. Columbia then determines the levels of recallable and non-recallable transportation capacity that is available for release. Non-recallable capacity is equal to the difference between Columbia's monthly firm entitlement level and the firm customer requirements at design day conditions. The monthly recallable capacity is then equal to the difference between the total capacity identified as releasable and the non-recallable component.

Q. Please explain the difference between recallable and non-recallable releases.

A. As the names imply, recallable releases provide the releasor with the ability to recall the capacity under the terms specified in the release agreement and in accordance with the interstate pipeline's tariff recall provisions. Non-recallable capacity releases conversely are not recallable by the releasor during the term of the release. Recallable capacity is generally less valuable to the assignee than is non-recallable capacity due to the interruptible nature of the release.

Q. How does Columbia conduct its economic analyses to develop its gas supply mix and projections of gas supply mix and cost?

A. Columbia's basic tool of analysis is the SENDOUT® Gas Planning System provided by Ventyx, Inc. of Atlanta, Georgia. SENDOUT® determines the "optimum" time-dependent levels of pipeline transportation service and storage service to be utilized to meet Columbia's prospective demand under various weather-related scenarios. SENDOUT® recognizes specific demand regions within Columbia's service territory and the pipeline capacity and supply sources that are available to each region.

Columbia updates supply prices, storage balances and other input data in SENDOUT® on an ongoing basis from a variety of published and private sources. Columbia utilizes SENDOUT® for both long-range and short-term operational planning.

Q. In calculating the least cost gas supply analysis, what price information is considered by the model?

A. Columbia prepares a monthly estimate of gas prices for use in its monthly planning process. The estimate generally reflects NYMEX prices but may be adjusted to reflect current knowledge of gas pricing trends. It is recognized that the natural gas futures prices traded daily in the commodity market fluctuate widely in response to technical analyses by traders, daily business news and the weather. Nonetheless, the NYMEX price represents the price that industry participants are willing to offer for gas at a given point in time. To recognize the unpredictable nature of gas prices, Columbia incorporates both high and low cost scenarios in its planning processes.

In addition to the projected cost of gas, Columbia incorporates demand and commodity transportation costs of all pipelines operating in its service territory.

Our goal in estimating prices is to project, as accurately as possible, the cost of supply to Columbia at the city gate. The SENDOUT® model utilizes the monthly estimate of gas prices and transportation fuel and commodity costs to develop city gate rates and a least cost plan for purchasing gas supplies.

Q. Earlier you mentioned the monthly planning process. Can you please elaborate?

A. The monthly planning process is utilized to determine how Columbia should manage its gas supply activity each month to minimize gas costs for its customers while maintaining system reliability. On a monthly basis, Columbia updates its projection of future gas prices over the near term and incorporates additional information including storage levels and reliability considerations into the SENDOUT® model. Columbia then conducts multiple analyses utilizing the SENDOUT® model, evaluating differing customer demand levels, transportation activity and prices to determine the level of flowing supplies and storage activity that will minimize gas supply costs while maintaining safe reliable service. The monthly planning analysis helps identify term and spot market purchase requirements, swing gas requirements, capacity release and off-system sales opportunities, and operational targets for storage. Upon completion of the monthly planning analysis, Columbia conducts an internal meeting where the results of the analysis are presented and discussed and a purchasing strategy is developed for the forthcoming month. The analysis is conducted before the beginning of each month and subsequently during the month as conditions dictate.

Q. Did Columbia issue any Operational Alerts or Operational Flow/Matching Orders during the 2014-15 winter season?

A. Yes, with the colder than normal temperatures experienced this winter, and in response to upstream pipeline restrictions, it was necessary for Columbia to issue several Operational Alert notices and Operational Flow/Matching Order (OFO/OMO) notices for the 2014-15 winter season.

Q. Did Columbia issue any Emergency Alerts during the 2014-2015 winter season?

A. No.

Q. Please describe briefly Columbia's Customer CHOICE℠ program.

A. Under the Customer CHOICE℠ program NGSs are required to deliver gas supplies to Columbia at a constant daily rate each day of the year. Columbia remains the SOLR and provides needed balancing services to match supply and demand for all customers.

Q. Please elaborate on the NGSs' delivery obligations under Columbia's Customer CHOICE℠ program.

A. Columbia's Customer CHOICE℠ program requires NGSs to deliver to Columbia's city gates, on a firm basis, an equal amount of gas every day of the year to satisfy their customers' annual gas requirements. Each month Columbia determines the normalized annual volumes for each NGS customer aggregation group. This volume is then divided by 365 to yield the volume of natural gas each NGS is required to deliver to Columbia for each of its aggregation groups each day of the year. Customer consumption above or below the normalized annual volumes are trued up to the NGS' actual deliveries annually.

Q. Please describe the aggregation groups and their purpose.

A. Aggregation groups allow NGSs to aggregate similarly situated customers, located within a given geographical area, for purposes of nominating and scheduling gas supplies to Columbia. Aggregations provide the NGS with the ability to combine customers so that the imbalances between supply and demand for multiple customers are netted together instead of requiring balancing for individual customers. The netting reduces the administrative requirements for both Columbia and the NGS. Aggregation groups also enable Columbia to manage the receipts of natural gas on its system when and where needed to ensure system reliability and therefore satisfy the requirements of its customers.

Q. Does Columbia anticipate any changes to this process?

A. Not at this time.

Q. May NGSs have more than one aggregation group?

A. Yes they may. Columbia requires each NGS to have a minimum of one aggregation group for all of its customers located within the geographic boundaries of each Columbia Transmission specified Market Area. These Market Areas are established by Columbia Transmission to facilitate the operational needs of its transmission system. Aligning the aggregation groups to these Market Areas is one means of assuring safe and reliable service.

Q. How do NGSs acquire firm capacity to participate in Columbia's Customer CHOICE℠ program?

A. Columbia's Customer CHOICE℠ program operates as a mandatory capacity assignment program, with one exception. The program allows NGSs participating in the CHOICE℠ program the opportunity to provide Other Primary FTS capacity should Columbia have a projected design day capacity deficiency. Each year, Columbia determines if its contracted capacity is sufficient to meet its projected design day demand. In the event it is not, Columbia will provide CHOICE℠ participating NGSs the opportunity to provide Other Primary FTS capacity that the NGS may utilize to provide supplies for its CHOICE℠ program customers. To the extent CHOICE℠ NGSs are able to provide Other Primary FTS, which has primary delivery point entitlements at a Columbia city gate, the NGS will be permitted to utilize that capacity in lieu of mandatory assignment from Columbia of a like volume. The volume of Other Primary FTS that CHOICE℠ NGSs may provide under this program is limited to any deficiency that Columbia may project for the forthcoming year. To the extent that an NGS is unable to provide Other Primary FTS that is acceptable to Columbia, the NGS must take mandatory assignment of FTS capacity from Columbia.

Q. Who is responsible for the payment of demand costs when the capacity is assigned to the NGS by Columbia?

A. As with other capacity release transactions, the assignee or the NGS has the responsibility to pay the pipelines directly for the assigned capacity. However, Columbia remains ultimately liable for charges in the event of non-payment of released capacity costs by the assignee.

Q. Does Columbia retain any capacity to provide service to the CHOICE^{SM} Program customers?

A. Yes. Columbia retains firm contract rights to all storage, other upstream pipeline and peaking capacity, if any.

Q. Who pays for the costs of this retained capacity?

A. The customers participating in the Customer CHOICE^{SM} Program pay the costs of this retained capacity. Columbia charges the participating customers a rate per Mcf of throughput to recover the costs Columbia incurs. This rate is equal to the Purchased Gas Demand Cost ("PGDC") charge in Columbia's sales tariff less the costs of Columbia Gulf and Columbia Transmission capacity, adjusted for storage injection and withdrawal charges.

Q. Please describe Columbia's obligations as a SOLR.

A. In general, the SOLR retains the responsibility to maintain safe and reliable service and ensure that adequate supplies are available to satisfy daily, seasonal and annual requirements for residential, small commercial, small industrial, other essential human needs customers and any other customer class determined by the Commission to fall within the SOLR function. Included in the SOLR function are sales to customers that have not chosen an alternate supplier, choose to be served by the SOLR, or are refused service by NGSs. The SOLR also provides supplies for customers whose NGS fails to deliver their requirements.

Q. Please describe how Columbia, as SOLR, maintains safe and reliable service.

A. Consistent with its role as a public utility, Columbia maintains safe and reliable service by providing those services it is uniquely qualified to provide and manage. These include: (1) management of distribution mains and services from the city gate to the burner tip; (2) determination of customer requirements; (3) management of city gate requirements; and (4) assuring that adequate capacity is available in the long-term to satisfy the requirements of its residential customers and the human need requirements of its small commercial and industrial customers even under extreme (design) conditions. Item (4) is closely aligned with Columbia's long-range planning efforts in assuring that adequate supplies and capacity are available to human needs customers as well as those other customers that contract for firm services from Columbia.

Q. Please describe Columbia's SOLR function as it pertains to distribution mains and services.

A. Columbia's SOLR responsibilities in this area include (a) field management of maintenance, customer service, regulation and measurement; (b) gas control operations; (c) management of any on-system storage, peaking or other supply related assets; and (d) determination of maximum daily delivery obligations

("MDDO") and pressure requirements at each point of delivery ("POD") with interstate pipelines.

Q. What SOLR responsibilities are incorporated in the determination of customer requirements?

A. SOLR responsibilities in this area include calculation of annual customer requirements and associated daily NGS deliveries, establishment of design day criteria and determination of firm and non-firm design day requirements.

Q. What are Columbia's SOLR obligations related to the management of city gate requirements?

A. The responsibilities related to management of city gate requirements include: (a) provision of no-notice city gate balancing to accommodate differences between supplier deliveries and customer demand, including GDS customers; (b) management of the annual true-up process; (c) evaluation of NGS requests for utilization of alternate delivery points; (d) maintenance of a no-notice back-up supply in the event of an NGS failure; (e) development and administration of a plan for dealing with an NGS failure; (f) development and maintenance of effective on-system nominations systems; and (g) development and enforcement of supply reliability requirements, including implementation of OFO/OMOs and other system management tools provided for in the tariff.

Q. What SOLR responsibilities are included in assuring that long-term capacities are available for human needs customers?

A. Reliability of service to human needs customers requires that access to firm capacity be without question. In today's energy environment, that assurance is only accomplished through the maintenance of long-term capacity assets that do not disappear because of an election of a supplier to exit the business, bankruptcy or more favorable economic options serving other segments of the natural gas marketplace. These human needs customers do not have a choice in the utilization of natural gas. They need it for the essential life sustaining uses of heating their homes and cooking their meals. The maintenance of firm capacity on an unquestioned basis is essential in assuring reliable service. This long-range process ensures that adequate pipeline capacity is available to satisfy customer requirements and that adequate contractual commitments exist at each POD to satisfy MDDO and pressure obligations. Also, as discussed earlier, active participation in FERC activities is a key part of the process.

Q. What gas supply and capacity resources does Columbia utilize to provide these SOLR functions?

A. Columbia will continue to utilize those assets presently under its control that are not assigned to NGSs under its Customer CHOICE℠ program. Included are capacity assets Columbia will require to maintain balancing services and/or system integrity for service to its customers. These are principally storage and storage-related transportation capacities. Additionally, all capacity assignments made to NGSs participating in Columbia's Customer CHOICE℠ program will be made on a recallable basis. If an NGS who has been assigned capacity fails to deliver supplies to Columbia in a manner consistent with Columbia's tariff, Columbia will recall this capacity, as needed, to maintain service to affected customers. While it is possible that Columbia may experience a delay in recalling capacity assigned to an NGS and filling that capacity with back up supplies, Columbia will be able to continue to provide adequate supplies to its customers from its retained storage on all but extremely cold days. Columbia's tariff also requires that any NGS that provides capacity under Columbia's Acquisition Process for New and Renewed Contracts and later leaves the Customer CHOICE℠ program must provide for that capacity to be assignable to Columbia until such time as Columbia is able to acquire equivalent replacement capacity.

Q. Please describe the status of Columbia's gas price hedging program.

A. Columbia agreed as part of the 2013 1307(f) proceeding to eliminate its hedging program. *See Joint Petition for Settlement* at Docket No. R-2013-2351073. Pursuant to the approved settlement agreement in that case, Columbia has not entered into any new hedges. However, prior to that time, Columbia had purchased 247 NYMEX contracts at an average rate of $4.37 for the 2014-15 winter season under its historic hedging program. These purchases were made consistent with its then Commission-approved hedging program. Columbia will use these futures contracts as provided under the prior hedging program and the

2013 1307(f) settlement agreement. March 2015 is the last month that previously purchased NYMEX contracts are in place.

Q. Please explain Columbia's Report Supporting Capacity for Contract Years 2015-16 through 2018-19.

A. Columbia's 2013 1307(f) settlement stated: "In future 1307(f) pre-filings, Columbia will file and provide to all parties a report identifying: (1) the level of peak day capacity retained consistent with its policy and this Stipulation and the results of the Peak Day Forecast; and (2) any adjustment to capacity taken pursuant to Columbia's policy and available contractual opportunities. …". Exhibit 15 provides the analysis required pursuant to the 2013 settlement agreement. Columbia's policy is to have sufficient capacity to be within a range of up to 103% of the highest of its projected design day firm requirements for the five year period of its Design Day Forecast. As shown in Exhibit 15, Columbia's existing Design day capacity is within this policy.

Q. Columbia manages its off-system sales and capacity release programs under its Unified Sharing Mechanism ("USM"). Please explain.

A. A market exists for NGDCs, such as Columbia, to market unbundled and rebundled gas and capacity products to non-traditional customers. Columbia's off-system sales and capacity release programs provide Columbia and its customers an opportunity to benefit from the unbundling of interstate pipeline services implemented by FERC Order 636. Columbia's off-system sales incentives began in January 1995 and capacity release incentives began in February 1996. During the time from inception of the incentives through September 2014, Columbia's customers will have received over $ 147 million dollars in off-system sales credits, and marketed capacity release credits.

In the Company's 2009 Section 1307(f) proceeding (Docket No. R-2009-2093219), the Commission approved a revision to the unified off-system sales and capacity release sharing mechanisms commencing October 1, 2009 and operating for a three-year period. The unified sharing mechanism established by the Commission's Order in Columbia's 2009 1307(f) proceeding was revised so that customers will receive 75% of the net USM proceeds while Columbia receives the remaining 25% of the incentive. In the Company's 2012 Section 1307(f) proceeding (Docket No. R-2012-2293303) the Commission approved the parties' agreement that Columbia's current 75% customer/25% Company USM shall continue indefinitely, absent Commission directive to the contrary.

Q. What have been the historical results of Columbia's USM?

A. Table 1 below lists the historic total off-system sales margins and capacity release revenues, and the Company and customer share and percentage. Actual data is provided for prior USM program sharing mechanisms through the year ending September 30, 2014. Data for the current USM program year ending September 30, 2015 includes actual booked margins through February 2015 and estimated incremental revenue from March 2015 through September 30, 2015.

TABLE 1

Historic Period	USM Total Margin	Customer Share	Customer Share	Company Share	Company Share
	($)	($)	(%)	($)	(%)
Oct 2002 – Sep 2003	$17,424,586	$8,556,146	46.10%	$8,868,440	50.90%
Oct 2003 – Sep 2004	$15,256,111	$8,539,028	55.97%	$6,717,083	44.03%
Oct 2004 – Sep 2005	$15,112,450	$10,556,225	69.85%	$4,556,225	30.15%
Oct 2005 – Sep 2006	$13,914,577	$9,957,288	71.56%	$3,957,289	28.44%
Oct 2006 – Sep 2007	$19,309,539	$13,691,677	70.91%	$5,617,862	29.09%
Oct 2007 – Sep 2008	$14,383,502	$10,243,451	71.22%	$4,140,051	28.78%
Oct 2008 – Sep 2009	$11,152,477	$8,106,734	72.69%	$3,045,743	27.31%
Oct 2009 – Sep 2010	$11,851,708	$8,888,781	75%	$2,962,927	25%
Oct 2010 – Sep 2011	$10,312,511	$7,734,383	75%	$2,578,128	25%
Oct 2011 – Sep 2012	$5,597,628	$4,198,221	75%	$1,399,407	25%
Oct 2012 – Sep 2013	$7,479,592	$5,609,694	75%	$1,869,898	25%
Oct 2013 – Sep 2014	$15,950,716	$11,963,037	75%	$3,987,679	25%
Oct 2014 – Sep 2015(Estimated)	8,102,460	6,076,845	75%	2,025,615	25%

As a result of the Commission's Order in Columbia's 2014 1307(f) case, Columbia has performed an evaluation of the existing allocation of the customer share of USM credits between the PGCC and the PGDC. This evaluation is provided as Exhibit No. 16 and is sponsored by Ms. Krajovic.

Q. Does this conclude your Direct Testimony?

A. Yes it does.

Columbia Gas of Pennsylvania, Inc
Firm Peak Day and Annual Entitlements
Contract Year 2015-16

Supply Source		Peak Day Entitlements Daily (MDth/Day)	Peak Day Entitlements Percentage (%)	Annual Entitlements (1) Annual (MDth/Yr.)	Annual Entitlements (1) Percentage (%)
Storage					
TCO FSS		456.9	68.09%	24,855	27.60%
DTI GSS	(2)	13.8	2.06%	941	1.04%
Equitrans 115SS	(3)	14.3	2.13%	0	0.00%
Total Storage		485.0	72.28%	25,796	28.64%
Firm Transportation (City Gate)					
TCO	(4)	132.4	19.73%	48,326	53.66%
Tennessee Gas Pipeline		19.3	2.88%	7,045	7.82%
Texas Eastern Transmission		19.3	2.88%	7,045	7.82%
National Fuel FTS		4.3	0.64%	1,570	1.74%
Total City Gate FTS		175.3	26.13%	63,985	71.04%
Blackhawk Storage		10.0	1.49%	30	0.03%
Local Production					
Direct into CPA	(5)	0.7	0.10%	256	0.28%
TOTAL CITY GATE SUPPLY		671.0	100.00%	90,066	100.00%
Firm Transportation (Upstream)					
Columbia Gulf	(4)	43.6	--	--	--
Tennessee		16.8	--	--	--
Texas Eastern		3.1	--	--	--
Total		63.5	--	--	--

(1) Includes seasonal storage entitlements. Equitrans seasonal entitlements of 1,500,000 Dth and DTI seasonal entitlements of 240,000 Dth are dedicated to Enhanced Balancing Service (EBS) Option 1 provided to General Distribution Service (GDS) customers, and are excluded from this Exhibit.

(2) For contract year 2015-16, 2,623 Dth of the winter season firm transportation capacity will be charged to and utilized in the provision of EBS Option 1.

(3) For contract year 2015-16, 7,839 Dth of the winter season firm transportation capacity will be charged to and utilized in the provision of EBS Option 1.

(4) Includes capacity assigned to Natural Gas Suppliers participating in Columbia's Customer CHOICE Program.

(5) Local Production purchased under Columbia's Posted Price Purchase Program. Additional purchases at Pennsylvania receipt points made by Columbia are included under TCO Firm Transportation Service capacity.

EXHIBIT HAC-2

Columbia Gas of Pennsylvania, Inc
Firm Peak Day Supplies vs Firm Demand
(MDth/Day)

Contract Year	2015/16	2016/17	2017/18	2018/19
Supply Source				
Storage				
TCO FSS	456.9	456.9	456.9	456.9
DTI GSS	13.8	13.8	13.8	13.8
Equitrans 115SS	14.3	14.3	14.3	14.3
Total Storage	485.0	485.0	485.0	485.0
Firm Transportation (City Gate)				
TCO	132.4	132.4	132.4	132.4
Tennessee Gas Pipeline	19.3	19.3	19.3	19.3
Texas Eastern Transmission	19.3	19.3	19.3	19.3
National Fuel FTS	4.3	4.3	4.3	4.3
Total City Gate FTS	175.3	175.3	175.3	175.3
Blackhawk Storage	10.0	10.0	10.0	10.0
Local Production				
Direct into CPA	0.7	0.7	0.7	0.7
TOTAL CITY GATE SUPPLY	671.0	671.0	671.0	671.0
2014 DDF FIRM REQUIREMENT	642.5	650.9	658.6	665.7
DIFFERENCE	28.5	20.1	12.4	5.3
% OF DEMAND	4.4%	3.1%	1.9%	0.8%
2014 DDF FIRM REQUIREMENT plus 3%	661.8	670.4	678.4	685.7
DIFFERENCE	9.2	0.6	(7.4)	(14.7)
% OF DEMAND	1.4%	0.1%	-1.1%	-2.1%

COLUMBIA STATEMENT NO. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
vs.	)	Docket No. R-2015-2469665
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF

NANCY J.D. KRAJOVIC

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

April 1, 2015

Q. Please state your name and business address.

A. My name is Nancy J. D. Krajovic and my business address is 121 Champion Way, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia") as Director, Rates and Regulatory Affairs.

Q. What are your responsibilities as Director of Rates and Regulatory Affairs?

A. I am responsible for developing and directing rate activity before the Pennsylvania Public Utility Commission ("Commission") as well as coordinating and representing the Company's position in a variety of regulatory matters and proceedings.

Q. What is your educational and professional background?

A. I hold a Bachelors of Science Degree in Accounting from Duquesne University and a Master of Business Administration from the University of Pittsburgh's Katz Graduate School of Business. I was employed by the Commission from 1984 through 1987 as an auditor. From 1988 through 2007, I held various regulatory positions at Duquesne Light Company including Regulatory Analyst, Rate Design Coordinator, Project Manager, Director of Regulatory Affairs and Manager of Regulatory Affairs. In those positions I acted as the primary interface with the Commission in the conduct of financial and management audits of Duquesne Light. Additionally, I was responsible for the interpretation and administration of Duquesne's retail and supplier tariffs. In 2007, I assumed the role of Manager, Commercial and Industrial Customers for Duquesne Light and held that position until May, 2009. In November of 2009, I joined Columbia as a Senior Regulatory Analyst and was promoted to my current position in June of 2011.

Q. Please describe the scope of your testimony in this proceeding.

A. I am responsible for the overall presentation of Columbia's case in this proceeding, including Exhibit No. 1 and Exhibit Nos. 1-A through 1-G, which were submitted in response to the Commission's requirements under 52 Pennsylvania Code 53.64, *et seq*. I will also briefly discuss the operation of the Company in the Commonwealth of Pennsylvania.

Q. Will you be sponsoring other exhibits?

A. Yes, I am also sponsoring Exhibit No. 7, filed in response to the Commission's requirement that the Company provide a list of agreements that exist between Columbia and other utilities, pipelines or jurisdictional customers to transport gas through its system. I am sponsoring Exhibit No. 9, submitted in response to the Commission's regulations that require that the Company provide a schedule depicting historic monthly end-user transportation throughput (known on Columbia's system as General Distribution Service) by customer, and Exhibit No. 11, that requests a detailed explanation of each rate structure or rate allocation change proposed in the filing. Finally, I am sponsoring Exhibit 16, Columbia's evaluation of whether the existing allocation of Unified Sharing Mechanism ("USM") credits between the purchased gas commodity charge ("PGCC") and the purchased gas demand charge ("PGDC") within the PGC should be modified, as required by the Commission in its order in last year's 1307(f) proceeding at R-

2014-2408268. I will also provide testimony that gives a status report on certain other matters arising out of Columbia's prior PGC proceedings.

Q. Were the exhibits prepared by you or by persons working under your direction?

A. Yes they were.

Q. Is the information contained within the exhibits you are sponsoring true and correct to the best of your knowledge and belief?

A. Yes it is.

Q. Please describe briefly the area Columbia serves in the Commonwealth.

A. Columbia is engaged in the business of furnishing natural gas distribution service to approximately 419,000 customers pursuant to certificates of public convenience and necessity issued by the Commission. Columbia provides service to numerous communities in 26 counties in Pennsylvania.

Q. Please identify the scope of the testimony of the Company's other witness in this proceeding.

A. Mr. H. Alan Catron, Director of Supply and Capacity Planning for Columbia's affiliated service corporation, NiSource Corporate Services Company in Columbus, Ohio, will provide testimony regarding the Company's gas supply plan, including information in support of the Company's least cost procurement strategy as contained in Exhibit No. 5. Mr. Catron will support Exhibit No. 1-D-1 through 1-D-3, Exhibit No. 2, Exhibit No. 4, Exhibit Nos. 4–A and 4-B, Exhibit Nos. 5-A and 5-B, Exhibit No. 6, Exhibit No. 8-A through 8-E, Exhibit No. 10, and Exhibit Nos. 12 through 15. Mr. Catron will also supply testimony regarding the Company's involvement in relevant FERC proceedings in support of Exhibit No. 3.

Q. Please explain Exhibit No. 1.

A. Exhibit No. 1 sets forth the proposed tariff filed in this proceeding for recovery of purchased gas costs. The tariff includes the proposed rates for each rate schedule, a Purchased Gas Cost Rider that describes the manner in which the Company will recover its purchased gas costs from sales customers and rates associated with standby service.

Q. What are the total projected changes in sales service rates to become effective October 1, 2015, for recovery of purchased gas costs?

A. Referring to the pre-filed data submitted on February 27, 2015, Exhibit No. 1–A, Schedule 1, Sheet 1 of 2, Columbia projected an overall decrease of $0.14050 per therm to its PGC rate for customers served under Rate RSS – Residential Sales Service, Rate SGSS – Small General Sales Service, and Rate LGSS – Large General Sales Service, as compared to rates in effect as of February 27, 2015. I note that this rate will likely be revised in the future, based upon updates to the filing.

Q. What are the principal reasons for this projected change in the overall PGC rate?

A. There are two reasons. The first is a decrease in gas costs for the Application Period projected at the time of the filing. Purchased gas costs are expected to decrease by approximately $0.12955 per therm, excluding the E-factor. The second reason is a projected increase of $0.01095 per therm in the level of over collections to be refunded through the E-factor during the Application Period over that being refunded currently. This increase in the E-factor refund combined with the decrease in projected gas costs results in the overall decrease of $0.14050 per therm.

Q. Are the calculations detailed in this filing impacted by Columbia's sharing of off-system sales and capacity release revenues?

A. Yes.

Q. Please describe the sharing mechanism.

A. Columbia has a Unified Sharing Mechanism ("USM") for the sharing of net revenues derived from off-system sales and capacity release programs. The net revenues are shared with 75% allocated to the customers and 25% retained by the Company. While the sharing allocation has remained consistent for many years, the methodology to project the revenues to be shared has been modified from time to time.

Q. How did the Company project the level of revenues to be shared in the pre-filing?

A. In the partial settlement reached in last year's proceeding at R-2014-2408268, the parties agreed to calculate the USM projection of the customers' share based on an average of the three most recently complete PGC periods for which data are available at the time of the Company's pre-filing. Accordingly, the calculation of the October 1, 2014 PGC reflected a projection based upon the three year average for the ending period ending September 30, 2013. The partial settlement also reflected the parties' agreement to consider in the instant proceeding whether to exclude the USM credit amount for the twelve month period ended September

30, 2014 from the average calculation on the basis that it is extraordinary and likely to distort the projection of the USM credits.

Q. How much was the USM credit revenue for the twelve months ended September 30, 2014?

A. The credits totaled $11,971,233. The revenues were unusually high due to the extreme cold temperatures experienced in the region during the winter of 2013/2014.

Q. How has the Company proposed to treat the $11,971,233 in the calculation of the projected USM credit revenue to be reflected in the PGC rates effective October 1, 2015?

A. The Company proposes to replace the USM revenues for the twelve months ended September 30, 2014 with a five year average of USM revenues over the period October 1, 2008 through September 30, 2013. This amount is then averaged with results for the twelve months ended September 20, 2013 to derive a three year average.

Q. Why has the Company proposed this substitution?

A. It is the Company's position that a five-year average would appropriately smooth annual fluctuations and provide a reasonable proxy for use in the calculation.

Q. Are you proposing any changes to the mechanism or the revenues to be shared between the customers and the Company in this proceeding?

A. I will summarize the Company's evaluation of and findings on the appropriate allocation of the credits between the PGDC and the PGCC later in my testimony.

The calculations of the credits in the pre-filing do not reflect any changes in allocation methodology.

Q. What credit was then included in the PGC calculated for the Application Period of October 2015 through September 2016?

A. The credit is projected at $5,549,510 allocated 60% to the PGCC and 40% to the PGDC.

Q. What does the Company project the total credit to be for the twelve months ended September 30, 2015?

A. The Company currently projects that total at $6,076,845.

Q. Please describe the Company's calculation of retainage.

A. In accordance with the Commission's orders in prior PGC proceedings (Docket Nos. R-2009-2093219 and R-2010-2161920), Columbia has calculated retainage based on a three-year rolling average, with an August 31st ending date for each year, which excludes Mainline-Class I customer quantities and includes company use in the calculation of retainage. Exhibit NJDK-1 to my testimony calculates the retainage rate to be effective January 2016 resulting from a three-year average ending August 31, 2014. The average rate remains consistently low.

Q. Please describe Exhibit No. 1-A, Schedule 1, Sheet 2.

A. This Sheet is included in Columbia's filing to demonstrate the calculation of the Daily Purchased Demand Rate under Rate SS. This calculation is based on the total estimated demand charges for the projected period October 2015 through September 2016, divided by Columbia's total demand billing determinants for the same period.

Q. Please describe Exhibit No. 1-A, Schedule 2.

A. Exhibit No. 1-A, Schedule 2, Sheets 1 through 4 detail the calculation of the over/under-collection for the period of October 2015 through September 2016. This schedule shows that the rates contained in Exhibit No. 1-A would recover the projected gas costs included in Columbia's filing based upon projected volumes. Any balance at the end of the period is due to rounding.

Q. Please describe Exhibit No. 1-A, Schedule 3.

A. Exhibit No. 1-A, Schedule 3 details the calculation of the purchased gas demand charge that is paid by customers selecting Columbia's CHOICE® service. Columbia's CHOICE® service offers residential customers and commercial customers an opportunity to purchase their natural gas supply service from a licensed Natural Gas Supplier ("NGS") under Rates RDS and SCD. Under CHOICE® service, NGSs are assigned, and pay for, a portion of Columbia's pipeline capacity. The NGS must deliver an amount of gas every day of the year that is equal to 1/365th of the NGS customer group's annual normalized consumption. Under the CHOICE® program, Columbia manages daily imbalances with retained capacity and storage. Those customers who select an NGS are subject to the purchased gas demand component of Columbia's purchased gas cost rate, net of a credit to reflect the cost of Columbia Gas Transmission, L.L.C. ("TCO") and Columbia Gulf Transmission L.L.C. ("Gulf") pipeline capacity assignable to their NGS. The credit for the upcoming PGC period is $0.03020/therm.

Q. Please describe Exhibit No. 1-B.

A. Exhibit No. 1-B is submitted in response to the Commission's filing requirement at §53.64(c)(1) and details the monthly projected purchases from the Company's various gas suppliers for the period October 2015 through September 2016. Exhibit No. 1-B consists of eleven schedules that detail and summarize the estimated purchased gas demand costs from TCO, Gulf, Texas Eastern Transmission Corp ("TETCO"), Dominion Transmission ("Dominion"), Tennessee Gas Pipeline Co. ("Tennessee"), National Fuel Gas ("National"), and Equitrans, and projected commodity purchases from various interstate suppliers, storage, and Pennsylvania local producers.

The monthly projected purchases included in Exhibit No. 1-B, Schedule 1, Sheet 1 of 4, are the twelve-month summary of the estimated demand and commodity costs of gas. As indicated on line 6 of Schedule 1, Sheet 1, the total projected cost of gas for the twelve-month period is $168,738,216.

Exhibit No. 1-B, Schedule 1, Sheet 2 of 4 summarizes the projected demand cost from Exhibit No. 1-B, Schedules 2 through 7 for the October 2015 through September 2016 period, by month and by pipeline. Schedule 1, Sheet 2 includes a fixed annual credit of $300,000 related to the provision of elective balancing services ("EBS") approved by the Commission in the settlement at Docket No. R-00016668. Schedule 1, Sheet 3 summarizes the projected commodity costs from Schedules 8 through 11 by month and by source. Schedule 1, Sheet 4 is a summary of the projected commodity quantities, in Dth, by month and by source. The demand and commodity costs have been brought forward to Exhibit No. 1-A to be used in the computation of changes in rates.

Q. Please continue with your explanation of the other schedules contained in Exhibit No. 1-B.

A. Exhibit No. 1-B, Schedules 2 through 7 detail the projected demand cost reflected on Schedule 1, Sheet 2. The projection of the demand costs for each pipeline is based on the projected monthly capacity and the projected demand rates.

Table 1 below summarizes those pipelines and the projected demand cost related to each:

Table 1

Projected Pipeline Demand Costs from Exhibit No. 1-B

Columbia Gas Transmission, LLC	Schedule 2, Sheet 1	$51,237,030
Columbia Gulf Transmission, LLC	Schedule 2, Sheet 2	$2,247,060
Texas Eastern Transmission Corporation	Schedule 3	$3,086,480
Dominion Transmission	Schedule 4	$681,132
Tennessee Gas Pipeline	Schedule 5	$5,021,892
National Fuel Gas Supply Corporation	Schedule 6	$195,252
Equitrans	Schedule 7	$256,491

Q. Please explain the development of the projected commodity cost reflected in Exhibit No. 1-B.

A. The projected commodity cost shown on Exhibit No. 1-B, Schedule 1, Sheet 3 is detailed in Schedules 8 through 11 of Exhibit No. 1-B. The detail of the projected commodity cost is by month and by source.

Schedule 8 details the projected purchases of gas under term contracts. Columbia will be utilizing transportation capacity on several pipelines and in different combinations for its term contracts. The purchase price for this gas reflects the commodity cost of the gas delivered to the city gate. The product of the projected purchases times the projected city gate purchase rates amounts to $50,742,657.

Schedule 9 details the projected purchases of spot gas (Line 9 - $53,468,121) and local gas (Line 15 - $721,201). The total projected cost of these purchases is $54,189,322. Mr. Catron is the witness responsible for the projection of wellhead prices used in the development of city gate prices on Schedules 8 and 9.

Schedule 10 shows the projected propane purchases by month. The propane purchases amount to $0.

Schedule 11 is a listing of the projected monthly gas commodity storage costs. Columbia will use storage from Dominion, Equitrans, and TCO. The total net cost of gas from storage is projected to be $1,380,900. This amount includes the injection/withdrawal charges and the transportation commodity costs. Monthly injections are priced at the average commodity cost of gas purchased for the month. Monthly withdrawals of gas from storage are based on the average cost of gas in storage for the month.

Q. Please continue your testimony by describing Exhibit No. 1-C.

A. Exhibit No. 1-C is submitted in accordance with § 53.64(c)(1) of the Commission's regulations and sets forth the total estimated purchased gas costs from all gas supply sources for the period February 2015 through September 2015. Exhibit No. 1-C consists of eleven schedules detailing the projected transportation and storage capacity cost of purchases from TCO, Gulf, TETCO, Dominion, Tennessee, National Fuel, and Equitrans, and projected commodity purchases from interstate suppliers, storage, financial hedges and Pennsylvania local producers. Mr. Catron provided the monthly purchase quantities.

Q. Please describe the schedules included in Exhibit No. 1-C.

A. Exhibit No. 1-C, Schedule 1, Sheet 1 sets forth the summary of the total estimated purchased gas costs, by month, for the period February 2015 through September 2015. Schedule 1, Sheet 2 summarizes the total estimated purchased gas demand costs by month and pipeline for the period February 2015 through September 2015.

Exhibit No. 1-C, Schedule 1, Sheet 3 summarizes the total estimated purchased gas commodity costs, by month and by source, which are further detailed on Schedules 8 through 11.

Exhibit No. 1-C, Schedule 1, Sheet 4 is a summary of the total estimated purchased gas commodity quantities, in Dth, by month and by source.

Q. Please explain the projected demand cost development.

A. Exhibit No. 1-C, Schedules 2 through 7 detail the projected demand costs reflected on Schedule 1, Sheet 2 by pipeline company. The projection of the demand costs for each pipeline company is based on the projected monthly capacity and the projected demand rates. Table 2 below summarizes those pipelines and the projected demand cost related to each:

Table 2 Projected Pipeline Demand Costs from Exhibit No. 1-C		
Columbia Gas Transmission, LLC	Schedule 2, Sheet 1	$31,434,582
Columbia Gulf Transmission, LLC	Schedule 2, Sheet 2	$1,498,040
Texas Eastern Transmission Corporation	Schedule 3	$2,024,640
Dominion Transmission	Schedule 4	$407,432
Tennessee Gas Pipeline	Schedule 5	$3,347,928
National Fuel Gas Supply Corporation	Schedule 6	$130,168
Equitrans	Schedule 7	$125,710

Q. Please explain the projected commodity cost development.

A. The projected commodity cost shown on Exhibit No. 1-C, Schedule 1, Sheet 3 is detailed in Schedules 8 through 11. The detail of the projected commodity cost is by month and by source.

Schedule 8 details the total estimated purchased gas commodity costs under term contracts. Columbia will be using transportation capacity on several pipelines and in different combinations. The purchase price for this gas reflects the commodity cost of the gas delivered to the city gate. The product of the projected purchases times the projected city gate purchase rates equals $18,071,345 of projected gas cost.

Schedule 9 provides details, for each month in the February to September 2015 period, of the total estimated purchased gas commodity costs associated with spot and local gas purchases. The projected cost of these purchases is $46,603,784 (Line 9 – $46,190,968 + Line 15 – $412,816). Mr. Catron is the witness responsible for the projection of wellhead prices used in the development of city gate prices on Schedules 8 and 9.

Schedule 10 shows the projected monthly purchases for propane. The propane purchases amount to $0.

Schedule 11 shows the total estimated purchased gas commodity costs associated with storage. Columbia will use storage from Dominion, Equitrans and TCO to provide service to customers. The total cost of gas from storage for the eight-month period February 2015 through September 2015 is projected to be ($8,337,669), which includes the injection/withdrawal charges and the transportation commodity cost. The monthly injection and withdrawal rates were developed utilizing the methodology discussed in relation to Exhibit No. 1-B, Schedule 11 (Page 11 of this testimony).

Q. Please describe the calculations contained in Exhibit No. 1-D.

A. As required by § 53.64(c)(1) of the Commission's regulations, Exhibit No. 1-D Schedule 1 sets forth the historic cost of gas by type and month for the February 2014 through January 2015 period. Section 53.64(c)(1) requires Columbia to file a complete listing of the sources of gas supply used in the prior twelve months that ends two months prior to the date of the Company's tariff filing. Exhibit No. 1-D consists of seven schedules detailing the historic cost of gas purchased from interstate sources through transportation arrangements with interstate pipelines, Pennsylvania local producers and underground storage. Exhibit No. 1-D, Schedule 1, Sheet 1 summarizes the total costs associated with the purchases. Exhibit No. 1-D, Schedule 1, Sheet 2 itemizes the demand and commodity costs shown on Exhibit No. 1-D, Schedule 1. Exhibit No. 1-D, Schedule 1, Sheet 3 details the volumes associated with the purchases. Exhibit No. 1-D, Schedules 2 through 7 provide additional detail on the purchases by type and month. Mr. Catron will support Exhibit Nos. 1-D-1 through 1-D-3.

Q. Please describe Exhibit No. 1-E.

A. Exhibit No. 1-E, which consists of six schedules, sets forth the calculations supporting the experienced net over/under-collection level used in the rate recovery calculation.

Q. Please explain how the implementation of Columbia's CHOICE® Service has affected the over/under-collection calculation.

A. In accordance with Columbia's Purchased Gas Cost Rider tariff, Columbia recovers a portion of purchased gas demand charges from residential and small commercial distribution customers. Because Columbia is collecting purchased gas demand costs from residential and small commercial distribution customers through its CHOICE® service, it is necessary to separate the over/under-collection of commodity costs and the over/under-collection of demand costs. Distribution customers who pay the purchased gas demand cost of gas are subject to the annual reconciliation of demand costs. Furthermore, for a one-year period after transferring from sales service, CHOICE® customers are subject to the commodity over/under-collection charge or credit. In the appropriate schedules contained in Exhibit No. 1-E, the reconciliation of the commodity and demand cost of gas are separated.

Q. Please describe Exhibit No. 1-E, Schedule 1.

A. Exhibit No. 1-E, Schedule 1 shows a summary of all components used in the calculation of the over/under-collection portion of the PGC rate scheduled to become effective October 1, 2015. Schedule 1, Line 12 reflects a total experienced net over-collection of ($13,384,960). This over-collection amount includes: anticipated over/under-collection during the 2014 § 1307(f) Application Period (October 2014 through September 2015); reconciliation of prior period proceeds received for off-system sales and capacity releases; and reconciliation of prior period over/under-collections and supplier refunds.

Q. Please explain the calculations on Exhibit No. 1-E, Schedules 2a and 2b.

A. Schedules 2a and 2b set forth the reconciliation of prior period commodity and demand costs from the 2013 PGC period of ($154,527) and $27,995 to be collected, respectively.

Line 20 of Schedule 2a reflects the estimated prior period commodity under-collection of ($154,527) that Columbia anticipates it will experience for the twelve months ending September 2015. This estimated commodity under-collection is calculated by adding: 1) the under-collected commodity balance as of September 30, 2014 (Line 1), 2) the beginning balance adjustment (Line 2), and 3) the sum of the actual and projected refunds and recoveries for the period October 2014 through September 2015 (Line 19).

Line 19 of Schedule 2b reflects the estimated demand over-collection of $27,995 that Columbia anticipates it will experience for the twelve months ending September 2015. This estimated demand over-collection is calculated by adding: 1) the over-collected demand balance as of September 30, 2014 (Line 1), 2) the beginning balance adjustment (Line 2) and 3) the sum of the actual and projected refunds and recoveries for the period October 2014 through September 2015 (Line 18).

Q. Please explain the beginning balance adjustment on Schedule 2a.

A. The ending balance of the Tennessee Gas Pipeline Refund being credited to SGSS customers through September 30, 2104 in accordance with the Commission Order at Docket No. P-2012-2314912 was an over-refund of $13,898. In the October 1, 2014 PGC Quarterly an estimated over-refund balance of $13,030 was included in the calculation of the commodity e-factor. The September estimate was not trued up to the September actual in the January 1, 2015 Quarterly filing and the true-up amount of ($868) is included here.

Q. Please explain the beginning balance adjustment on Schedule 2b.

A. As stated in footnote 2 on Schedule 2b, the adjustment records an exchange fee of $450 that had not been recorded in demand costs for February 2014 and is therefore included here for recovery.

Q. Please explain the calculations on Schedules 3a and 3b.

A. Schedules 3a and 3b reflect the calculation of the estimated net under-distributed USM proceeds of $196,384, as shown on Exhibit No. 1-E, Schedule 1, line 4. The purpose of this calculation is to estimate the portion of the USM proceeds that will be credited during the current PGC period. Original and quarterly rates are presented in the manner described previously with respect to Schedules 2a and 2b.

Q. How was the estimated net underdistributed amount of $196,384 for USM proceeds determined?

A. As indicated on Exhibit No. 1-E, Schedules 3a and 3b, Columbia has included in the E-factor a projected total credit of $6,077,000 for the USM. This is the current estimate of off-system sales cost of gas for the twelve months ended September 30, 2015. This amount is allocated 60% to the Purchased Gas Commodity Cost ("PGCC") (Schedule 3a, Line 19) and 40% to the Purchased Gas Demand Cost ("PGDC") (Schedule 3b, Line 18).

Schedule 3a compares the actual and estimated USM commodity amounts to be passed back for the twelve months ended September 30, 2015 to the $3,646,200 allocated to the PGCC. The net result is an estimated remainder of $105,966 to be passed back to customers commencing October 1, 2015.

Schedule 3b compares the actual and estimated USM demand amounts to be passed back for the twelve months ended September 30, 2015 to the $2,430,800 allocated to the PGDC. The net result is an estimated remainder of $90,418 to be passed back to customers commencing October 1, 2014.

I note that after the actual USM credit for the twelve months ended September 30, 2015, is known, Columbia will reconcile the actual credit to the actual amount provided to the customers through the current credits of $(0.01052)/therm (commodity) and $(0.00498)/therm (demand).

Q. Please explain the adjustment on Line 18 of Schedule 3a and Line 17 of Schedule 3b.

A. At the time of the October 1, 2014 Quarterly PGC filing, actual data for September 2014 was not available for reconciliation of credit activity and was therefore estimated. The estimates should have been reconciled in the January 1, 2015 Quarterly PGC filing but were overlooked at that time. The true-ups are accomplished through these adjustments.

Q. Will you please continue with your explanation of Exhibit No. 1-E, Schedule 4?

A. Schedule 4 reflects the statement of over/under-collections expected from the application of Columbia's PGC rates for the period October 2014 through September 2015. The monthly over/under-collection amounts for the period October 2014 through January 2015 are based on actual data. The monthly over/under-collection amounts for the period February 2015 through September 2015 are based on projected data. I note that, under the Commission's PGC regulations, the projected amounts will be replaced with actual costs and recoveries through August 2015 as part of Columbia's compliance filing. Exhibit No. 1-E, Schedule 4, Sheet 1a depicts the calculation of the commodity over/(under) collection while Exhibit No. 1-E, Schedule 4, Sheet 1b depicts the calculation of the demand over/(under) collection. The estimated total over-collection of $12,617,423, derived by combining both sheets, is carried forward to Exhibit No. 1-E, Schedule 1, line 6. Likewise, interest associated with the commodity and demand under collections totaling $697,685 is also calculated on

Exhibit No. 1-E, Schedule 4, Sheets 1a and 1b respectively, and is carried to Exhibit No. 1-E, Schedule 1, line 8, so that it is included in the E-factor.

Q. How was interest calculated?

A. Interest is calculated at the rate of 8% for the months of October 2014 through January 2015 for commodity over/under collections from gas costs. In accordance with the Public Utility Code, Columbia applies an interest rate of 6% in the event of a net under-collection of gas costs and 8% in the event of a net over-collection. As has been determined by the Commission and the Commonwealth Court, the determination of whether a net under-collection or a net over-collection has been experienced is to be based upon the historic reconciliation period, which for Columbia is the twelve-month period ending January 31. Columbia experienced a net over-collection of $6,743,062 for commodity cost of gas for the twelve months ended January 31, 2015 (Exhibit No. 1-F, Schedule 1, Sheet 1a of 7). Columbia experienced a net over-collection of $7,535,981 for demand cost of gas for the twelve months ended January 31, 2015 (Exhibit No. 1-F, Schedule 7, Sheet 1b of 7) and therefore continued to use 8% for the months October 2014 through January 2015. In addition, Columbia has included a projection of interest at 8% for the period February 1, 2015 through September 30, 2015, on the monthly under-collections and over-collections, resulting in a net interest amount of $697,685 for the twelve months ending September 30, 2015. Columbia will update the interest rate, if necessary, for the February through September 2015 period in next year's 1307(f) filing based on the net over or under collection for the twelve months ending January 31, 2016.

Q. How is the cost of fuel recovery calculated?

A. The cost of fuel recovery is shown on Schedule 4, Sheet 1a, Column 1 and Sheet 1b, Column 1. Columbia's purchased gas cost recovery rates applicable to customers receiving service under Rate RSS, Rate SGSS, and Rate LGSS consist of both PGCC and PGDC components. General Distribution Service customers on Rate Schedules SGDS, SDS, LDS, MLDS, NCS, GDS, as well as NGSs with aggregation service, who purchase gas from Columbia, pay a fall-back rate for any gas commodity purchases they might make from Columbia, based on a monthly index price. Rate NSS – Negotiated Sales Service customers pay a cost of gas based on the cost of spot purchases scheduled to flow on the first day of the month. Customers receiving service under Rate SGDS Priority One, Rate SCD and RDS pay only the PGDC rate for volumes transported. Exhibit No. 1-E, Schedule 4, Sheet 2a, column 2 shows the PGCC rate that is applied to all sales under Rate RSS, Rate SGSS and Rate LGSS and the gas cost rate applied to all gas sales made to General Distribution Service customers (labeled "interruptible" on this schedule). Exhibit No. 1-E, Schedule 4, Sheet 3a, column 3 shows the recovery of gas costs from NSS customers.

Q. Please explain the calculation of the total demand revenue included in Exhibit No. 1-E, Schedule 4, Sheet 1b, column 5 that was used to calculate the over/under-collection included in the pre-filing information.

A. Exhibit No. 1-E, Schedule 4, Sheet 1b, column 5 summarizes the total purchased gas demand revenue collected from customers. The details of the purchased gas demand revenue are shown on Sheets 4a through 6. Estimated total purchased gas demand revenue recovery is $61,554,895.

Q. Please explain the calculation of the EBS Option 2 revenue in Exhibit No. 1-E, Schedule 4, Sheet 1b, column 2 that was used to calculate the over/under-collection.

A. Exhibit No. 1-E, Schedule 4, Sheet 1b, column 2 summarizes Rider EBS Option 2 revenues collected from General Distribution Service customers and NSS customers. The detailed calculation of the revenue is shown on Exhibit No. 1-E, Schedule 4, Sheet 6. Estimated total balancing revenue for the period October 2014 through September 2015 is $2,162.

Q. Please explain the calculation of Capacity Release Revenue under Rate NSS as contained on Schedule 4, Sheet 1b, column 4.

A. The calculation of the Capacity Release revenues from Rate Schedule NSS is detailed on Exhibit No. 1-E, Schedule 4, Sheet 6. Estimated total revenue from NSS Capacity Release for the period October 2014 through September 2015 is $5,100.

Q. Columbia's tariff contains several special provisions for Rate NSS. One provision is that any customer served under rate NSS with an annual throughput requirement below 64,400 therms be reported through the 1307(f) process. Does Columbia have any such customers?

A. No.

Q. What is calculated in Exhibit No. 1-E, Schedule 5?

A. Schedule 5 sets forth the commodity and demand refunds received from various suppliers. Exhibit No. 1-E, Schedule 5, Sheet 1 shows that there were no commodity refunds received from suppliers during the September 2014 through September 2015 period. Exhibit No. 1-E, Schedule 5, Sheet 2 shows that there were no demand refunds received from suppliers during the September 2014 through September 2015 period.

Q. Did Columbia receive any penalty credits from upstream pipeline suppliers during the twelve months ended February 28, 2015?

A. Yes. On December 10, 2014, Columbia received penalty credits of $1,323,179.23 from Columbia Gas Transmission Company. These credits do not correspond to charges reflected in the interstate pipelines' rates and, consequently, the credits do not correspond to gas costs that the Company has previously passed through or will in the future pass through to its customers. Rather, the monies were generated by third parties on the interstate pipelines systems that violated the terms of the interstate pipelines tariffs. As a disincentive to assess onerous penalties, FERC precluded the interstate pipelines from retaining these monies and required them to distribute the monies to non-offending shippers.

Q. What is Columbia's proposed treatment of these monies?

A. On February 2, 2015, Columbia filed with the Commission a Petition requesting approval to use the $1,323,179.23 to assist its residential and non-residential PGC customers by: (1) providing $957,981.76 of the penalty credit proceeds as additional funding the Hardship Fund; and (2) providing $365,197.47 of the penalty credit proceeds to non-residential PGC customers through the Company's PGC rates. Columbia determined the foregoing split based upon the recent projected firm demand of its residential and non-residential PGC customers.

Q. Have penalty credits received in the past been treated in a similar manner?

A. Yes. In the Settlement approved by the Commission's September 13, 2012 Order in Columbia's 1307(f) proceeding at R-2012-2293303, the parties agreed to the same disbursement methodology for penalty credits received in 2010 and 2011. As noted in discovery in subsequent 1307(f) proceedings, no penalty credits were received in 2012 or 2013.

Q. Please describe Exhibit No. 1-F, Schedule 1.

A. Schedule 1 of Exhibit No. 1-F constitutes Columbia's statement of over/under-collections during the twelve months ended January 31, 2015. This schedule, which is submitted in compliance with § 53.64(i)(1)(i)-(iv) of the Commission's regulations, reflects an over-collection of $14,279,043 as detailed on Schedule 1, Sheet 1. Exhibit No. 1-F, Schedule 1, Sheets 1a and 1b respectively depict the calculations for the commodity over/under collection, the demand over/under collection, the commodity over/under collection with an itemization for Rate Schedule NSS, and the demand over/under collection with an itemization for Rates SS and NSS. Exhibit No. 1-F, Schedule 1, Sheets 2a through 2c provide detail of commodity cost recovery by month for the months of February 2014 through January 2015, and Sheets 3a and 3b provide the same information for Rate NSS commodity cost recovery. Exhibit No. 1-F, Schedule 1, Sheets 4a through 4d detail the demand cost recovery for the time period February 2014 through January 2015. Exhibit No. 1-F, Schedule 1, Sheet 5 details the demand cost recovery for standby service, and Exhibit No. 1-F, Schedule 1, Sheets 6a and 6b detail the volumes and revenues received from Rate NSS customers. Exhibit No. 1-F, Schedule 1, Sheet 7 reconciles the differences between the Company's total purchased gas costs, as reflected on Exhibit No. 1-D and the Company's financial statements, with the cost of fuel shown for PGC purposes which appears on Exhibit No. 1-E. Exhibit No. 1-F, Schedule 1, Sheet 7b reconciles the gas commodity purchases reflected in Exhibit 1-D and the commodity cost of fuel for PGC purposes shown on Exhibit 1-F, Schedule 1, Sheet 1a, as agreed to in the Settlement of the 1307(f) proceeding at R-2012-2293303.

Q. Please explain Exhibit No. 1-F, Schedule 2.

A. Exhibit No. 1-F, Schedule 2, attached to my testimony, complies with § 53.64(i)(1)(iv) and (v) of the Commission's regulations. This schedule details the difference between actual costs for the period February 2014 through January 2015, and projected costs included in the gas cost recovery components established in the 2012 § 1307(f) proceeding for the period February 2014 through September 2014, and in the 2014 § 1307(f) proceeding for the period October 2014 through January 2015.

Q. Please explain Exhibit No. 1-G.

A. In accordance with the terms of the Settlement for the 2013 1307(f) proceeding, noted above, the Company has included a copy of the experienced Exhibit 1-E for the prior year's PGC Application Period. It has been designated as Exhibit No. 1-G to distinguish it from the data for the current year PGC Application Period.

Q. Turning to Exhibit No. 7, would you please describe that exhibit?

A. Exhibit No. 7 was included in the pre-filing data submitted by Columbia in this proceeding on February 27, 2015. It was submitted in accordance with § 53.64(c)(8) of the Commission's regulations which require the Company to provide:

> A list of agreements to transport gas by the utility through its system, for other utilities, pipelines, or jurisdictional customers including the quantity and price of said transportation.

As noted in Exhibit No. 7, Columbia does not presently transport gas for intrastate or interstate pipelines.

Q. Please describe Exhibit No. 9.

A. Exhibit No. 9 provides a summary of transportation throughput, by customer, by month. This exhibit is submitted in compliance with § 53.64(c)(9) of the Commission's regulations, which requires the Company to provide a schedule depicting historic monthly end-user transportation throughput. Exhibit No. 9, Schedule 1 shows the throughput for CHOICE® customers by rate schedule by month for the period February 1, 2014 through January 31, 2015. Exhibit No. 9, Schedule 2 shows throughput for General Distribution Service customers (also known as "traditional" transportation customers) by month by rate schedule for the same period.

Q. Please explain Exhibit No. 11.

A. Exhibit No. 11 is submitted as required by § 53.64(c)(11) of the Commission's regulations, which requires the Company to detail rate structure or rate allocation changes proposed in this filing. As noted in Exhibit No. 11, Columbia has not proposed any rate structure or rate allocation changes in this filing.

Q. Are there any Columbia requirements for this 1307(f) filing as a result of the Commission order or approved settlement agreement from the 2014 1307(f) case at Docket No. R-2014-2408268?

A. Yes. The Company was required to appropriately demonstrate in this filing that the cost of the 5,215 Dth of capacity released to a large industrial customer is not included in projected demand costs and that 100% of the revenues from the release are returned to PGC customers.

Q. Please identify the schedules that demonstrate the Company's compliance with those requirements.

A. The projected capacity to be released to the large industrial customer is removed from the demand on Exhibit 1-B, Schedule 2, Sheet 1 of 2, line 2 and therefore from projected demand costs. The adjustment is also reflected on Exhibit 1-C, Schedule 2, Sheet 1 of 2, line 2. Exhibit 1-D, Schedule 6, Sheet 2 of 21, column 4 includes monthly adjustments to reflect 100% of the revenues associated with release of the 5,215 Dth at the maximum rate as a credit to demand costs reconciled through the PGDC.

Q. Were there any other requirements?

A. Yes. Columbia was required to present an evaluation of whether the existing allocation of USM credits between the PGCC and the PGDC within the PGC should be modified.

Q. Has Columbia completed this requirement?

A. Yes. The order required that the evaluation be included with the pre-filing data for this year's 1307(f) proceeding. Exhibit 16 of the pre-filing data submitted on February 27, 2015 included the Company's evaluation and response to the specific questions set forth in the order.

Q. Can you summarize the Company's evaluation and findings?

A. Yes. Columbia included data showing that over the four year period from October 2010 through September of 2014 Capacity Release ("CR") transactions have generated approximately 19.0% of total revenues subject to the USM and Off-System Sales ("OSS") transactions have generated the balance of approximately 81.0%. Currently under the USM, 40% of the shared revenues are allocated to the PGDC and 60% are allocated to the PGCC. Capacity Release utilizes only capacity in the determination of its value. Recognizing the blended nature (demand and capacity values) of the resources used for OSS other than CR (Sales, Options, AMA and Exchanges), the allocation procedure could be modified such that the percentage of revenues allocated to the PGDC could be based on two factors, the first being the percentage of CR to total OSS and CR based on a four year average. The second factor would be calculated based on the current CHOICE participation rate applied to the percentage of revenues derived from Sales, Options, AMA and Exchanges based on a four year average. The revenues allocated to the PGCC would be the remainder following the calculation of the PGDC percentage. Application of this methodology would allocate a portion of the value of non-capacity release revenue to the CHOICE customers commensurate with levels of CHOICE participation. If CHOICE participation reached 100%, then 100% of the customers' share of the CR and OSS would be credited to the PGDC. Columbia has not reflected this alternative calculation in the allocation of USM credits between the PGCC and PGDC in its filing, but offers it as an alternative methodology.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

§ 53.64(i)(1)(iv)(v)

(i) Utilities shall comply with the following:

(1) Thirty days prior to the filing of a tariff reflecting increases or decreases in purchased gas expenses, gas utilities under 66 Pa.C.S. § 1307(f) recovering expenses under that section shall file a statement for the 12-month period ending 2 months prior to the filing date under 66 Pa.C.S. § 1307(f) as published in accordance with subsection (b) which shall specify:

(iv) Evidence explaining how actual costs incurred differ from the costs allowed under subparagraph (ii).

(v) How these costs are consistent with a least cost fuel procurement policy, as required by 66 Pa.C.S. § 1318 (relating to determination of just and reasonable natural gas rates).

Response:

Exhibit No. 1-F, Schedule 1 of Columbia's 2015 1307(f) filed February 26, 2015, constitutes the Company's Statement of Over/Under Collections From Gas Cost Rate, as required by Section 53.64(i)(1) for the twelve month period ended January 31, 2015. Exhibit No. 1-F, Schedule 1, Sheet 1 indicates that Columbia was overcollected by $14,279,043 at January 31, 2015, resulting from gas costs of $216,131,650 and gas cost recoveries of $230,410,693.

A company’s experienced overcollections or undercollections are caused by variances that occur between projected and actual gas costs, and between projected and actual gas cost recoveries.

The projection of gas cost recoveries follows the 1307(f) cycle through a period of undercollections during months of high usage, followed by a period of overcollections occurring during months of low usage. Therefore, the months of February through September typically produce a net overcollection. In its PGC filing effective January 1, 2014, Columbia projected gas costs for February 2014 through September 2014 of $99,570,153. Gas cost recoveries were projected at $118,330,211 for this same period of time. Accordingly, these months were projected to produce a net overcollection of $18,760,058 (Exhibit 1-A, Schedule 2, Sheet 4).

Actual gas costs for the months of February 2014 through September 2014 (2015 1307(f) Exhibit 1-F, Schedule 1) totaled $110,910,275, a $11,340,122 increase from the projections included in the January 1, 2014 PGC filing. As Columbia progressed through the 2013 1307(f) period and incrementally adjusted its recovery rates in subsequent filings, recoveries for the same period of time were recorded at $139,198,870, representing a increase in gas cost recoveries of $20,868,659 from the January 1, 2014 PGC filing projections. In total Columbia experienced a net overcollection for the months of February 2014 through September 2014, which ended the 2013 1307(f) cycle, in the amount of $28,288,597.

As Columbia's computation of interest on over/under collections overlaps two separate

1307(f) periods, the remaining months of October 2014 through January 2015 will now be discussed.

In the October 1, 2014 PGC filing (Exhibit 1-A,Schedule 2, Sheet 4), Columbia projected gas costs for the months of October 2014 through January 2015 to total $102,731,757 with gas cost recoveries for the same period projected at $87,744,124, for an expected undercollection of $14,987,633. Columbia's actual gas costs for the months of October 2014 through January 2015 (2015 1307(f) Exhibit 1-F, Schedule 1) were $105,221,376, which is an increase from October's gas cost projections of $2,489,619. As Columbia progressed through the 2014 1307(f) period and incrementally adjusted its recovery rates in subsequent filings, recoveries for the months of October 2014 through January 2015 were recorded at $91,211,822 (2015 1307(f) Exhibit 1-F, Schedule 1). This is an increase of $3,467,698 when compared with the October 1, 2014 gas cost recovery projections. Overall, the net variance between projected gas costs and gas cost recoveries for the months of October 2014 through January 2015 resulted in a net undercollection of $14,009,554.

Together the net overcollection from the 2013 1307(f) months of February 2014 through September 2014 of $28,288,597 and the net undercollection of $14,009,554 for the 2014 1307(f) months of October 2014 through January 2015 results in a total net overcollection of $14,279,043 for the twelve month period ending January 31, 2015.

The net overcollection consists of a commodity overcollection of $6,743,062 and a demand overcollection of $7,535,981.

Columbia Gas of Pennsylvania

Exhibit NJDK-1

	YE Aug-31	2012 Dth	2013 Dth	2014 Dth	3-Year Averages 2012 - 2014	
	Supply					
1	Raw Supply Numbers	71,084,683	80,239,481	87,710,731	79,678,298	
2	Supply Adjustment	0	0	0	0	
3	Cumulative Adj. Supply - Including Supply Adjustments	71,084,683	80,239,481	87,710,731	79,678,298	
4						
5	ML1 Volumes	3,164,185	2,857,442	2,890,675	2,970,767	
6	Cumulative Adj. Supply Including Supply Adj. Less ML1	67,920,498	77,382,039	84,820,056	76,707,531	
7	Excess Pressure Volumes	21,668,250	23,284,523	24,540,283	23,164,352	
8	Cumulative Adj. Supply Including Supply Adj. Less Excess Pressure and ML1	46,252,248	54,097,516	60,279,773	53,543,179	
	Consumption					
9	Residential	28,668,655	34,702,583	38,587,744	33,986,327	
10	Commercial	19,226,157	23,234,476	25,412,727	22,624,453	
11	Industrial	21,868,980	21,400,408	23,036,438	22,101,942	
12	Other	75	0	5,335	1,803	
13	Electric Gen.	528,019	362,233	159,916	350,056	
14	Company Use	73,038	84,882	89,520	82,480	
15	Subtotal Consumption	70,364,924	79,784,582	87,291,680	79,147,061	
16	ML1 Volumes	3,164,185	2,857,442	2,890,675	2,970,767	
17	Excess Pressure	21,453,713	23,053,983	24,297,310	22,935,002	
18	Total Consumption - Includes Company Use but not ML1 (18 = 15 - 16)	67,200,739	76,927,140	84,401,005	76,176,295	
19	Total Consumption-Includes Company Use Less ML1 and Excess Pressure (19 = 18 -17)	45,747,026	53,873,157	60,103,695	53,241,293	
	Retainage					
19	Retainage-Includes Company Use Less ML1	792,797	539,781	508,571	613,716	
20	Rate (20 = 19 / 6)	1.2%	0.7%	0.6%	0.8%	
21	Retainage - Includes Company Use but not ML1 nor Excess Pressure	578,260	309,241	265,598	384,366	
22	Rate (22 = 21 / 8)	1.3%	0.6%	0.4%	0.7%	(1)

(1) Rate to be in effect as of January 1, 2016.

COLUMBIA GAS OF PENNSYLVANIA, INC.

121 Champion Way, Suite 100 **Canonsburg, Pennsylvania**

RATES AND RULES

FOR

FURNISHING GAS SERVICE

IN

THE TERRITORY AS DESCRIBED HEREIN

ISSUED: April 1, 2015 EFFECTIVE: October 1, 2015

ISSUED BY: M. R. KEMPIC, PRESIDENT
121 CHAMPION WAY, SUITE 100
CANONSBURG, PENNSYLVANIA 15317

NOTICE

This Tariff Supplement Makes Changes to the Existing Tariff —See Page No. 2

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
Cover	Tariff Cover Page	Supplement No., Issue and Effective Date.
2-2a	List of Changes	List of Changes.
2b-2g	List of Changes	Held for Future Use.
16	Rate Summary	The "Gas Supply Charge" has decreased. The "Gas Cost Adjustment" has increased. The "Pass-through Charge" has increased. The "Total Effective Rate" has decreased.
17	Rate Summary	The "Gas Supply Charge" has decreased. The "Gas Cost Adjustment" has increased. The "Pass-through Charge" has increased. The "Total Effective Rate" has decreased.
18	Rate Summary	The "Gas Supply Charge" has decreased. The "Gas Cost Adjustment" has increased. The "Pass-through Charge" has increased. The "Total Effective Rate" has decreased.
19	Rate Summary	The "Gas Supply Charge" has decreased. The "Gas Cost Adjustment" has increased. The "Pass-through Charge" has increased. The "Total Effective Rate" has decreased.
20	Rate Summary	The "Residential Price-to-Compare" has decreased. The "Commercial Price-to-Compare" has decreased The "Standby Service" has increased.
21	Rider Summary	The "Merchant Function Charge – Rider MFC" has decreased.
21a	Gas Supply Charge Summary	The "PGCC" has decreased. The "Rider MFC" has decreased. The "Total Gas Supply Charge" has decreased.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
21b	Pass-through Charge Summary	The “PGDC” has increased. The “Capacity Assignment Factor” has increased. The “Total Pass-through Charge” has increased
21c	Price-to-Compare Summary	The “PGCC” has decreased. The “Gas Cost Adjustment” has increased. The “Capacity Assignment Factor” has increased. The “Rider MFC” has decreased. The “Total Price-to-Compare” has decreased.
151	Rider PGC	The rates for “Rider PGC – Purchased Gas Cost” have changed.
154	Rider PGC	The rates for “Rider PGC – Purchased Gas Cost” have changed.

Rate Summary

Rate per thm

Residential Rate Schedules		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-Through Charge 2/	State Tax Adjustment Surcharge 3/	Total Effective Rate
Rate RSS - Residential Sales Service							
Customer Charge	$	16.75	-	-	-	0.00	16.75
Usage Charge	$	0.42138	0.32117	(0.03547)	0.19939	0.00000	0.90647
Customer Transferring from Rate Schedule RDS - Usage Charge	$	0.42138	0.32117	- 4/	0.19939	0.00000	0.94194
Rate RDS - Residential Distribution Service							
Customer Charge	$	16.75	-	-		0.00	16.75
Usage Charge:							
Customers Electing CHOICE - 1st Year	$	0.42138	-	(0.03547) 5/	0.16919	0.00000	0.55510
Customers Electing CHOICE - 2nd Year	$	0.42138	-	-	0.16919	0.00000	0.59057

1/ Please see Page No. 21a for rate components.
2/ Please see Page No. 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
4/ If a customer transfers to RSS from RDS, the Gas Cost Adjustment shall not be billed for twelve billing cycles.
5/ If a customer transfers to RDS from RSS, the Gas Cost Adjustment shall be billed for twelve billing cycles.

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules <= 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Total Effective Rate	
Rate SGSS - Small General Sales Service								
Customer Charge:								
Annual Throughput <= 6,440 thm	$	21.25	-	-	-	0.00	21.25	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00	-	-	-	0.00	48.00	
Usage Charge	$	0.31385	0.31811	(0.03547)	0.12553	0.00000	0.72202	
Customers Transferring from Rate Schedule SCD - Usage Charge	$	0.31385	0.31811	- 4/	0.12553	0.00000	0.75749	
Rate SCD - Small Commercial Distribution								
Customer Charge:								
Annual Throughput <= 6,440 thm	$	21.25	-	-	-	0.00	21.25	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00	-	-	-	0.00	48.00	
Usage Charge:								
Customers Electing CHOICE - 1st Year	$	0.31385	-	(0.03547) 5/	0.09533	0.00000	0.37371	
Customers Electing CHOICE - 2nd Year	$	0.31385	-	-	0.09533	0.00000	0.40918	
Rate SGDS - Small General Distribution Service								
Customer Charge:								
Annual Throughput <= 6,440 thm	$	21.25	-	-	-		21.25	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00	-	-	-		48.00	
Usage Charge:								
Priority One DS	$	0.28791	-	- 5/	0.12553	0.00000	0.41344	6/
Non-Priority One DS	$	0.28791	-	- 5/		0.00000	0.28791	6/

1/ Please see Page 21a for rate components.
2/ Please see Page 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
4/ If a customer transfers to SGSS from SCD or SGDS, the Gas Cost Adjustment shall not be billed for twelve billing cycles.
5/ If a customer transfers to SCD or SGDS from SGSS, the Gas Cost Adjustment shall be billed for twelve billing cycles.
6/ Plus Rider EBS Option 1 or 2 - See Page 21.

Issued: April 1, 2015
Effective: October 1, 2015

Mark R. Kempic - President

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules > 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment		Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Total Effective Rate	
Rate LGSS - Large General Sales Service									
Customer Charge:									
Annual Throughput > 64,400 thm and <= 110,000 thm	$	170.00					0.00	170.00	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	640.00					0.00	640.00	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,300.00					0.00	1,300.00	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,300.00					0.00	2,300.00	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,800.00					0.00	4,800.00	
Annual Throughput > 7,500,000 thm	$	7,400.00					0.00	7,400.00	
Usage Charge:									
First 11,000 thm per billing cycle	$	0.22209	0.31653	(0.03547)	4/	0.12544	0.00000	0.62859	
Next 43,000 thm per billing cycle	$	0.18672	0.31653	(0.03547)	4/	0.12544	0.00000	0.59322	
Next 54,000 thm per billing cycle	$	0.16663	0.31653	(0.03547)	4/	0.12544	0.00000	0.57313	
All thm per billing cycle over 108,000	$	0.11416	0.31653	(0.03547)	4/	0.12544	0.00000	0.52066	
Rate SDS - Small Distribution Service									
Customer Charge:									
Annual Throughput > 64,400 thm and <= 110,000 thm	$	170.00	-	-		-	0.00	170.00	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	640.00	-	-		-	0.00	640.00	
Usage Charge	$	0.16738	-	-	5/	-	0.00000	0.16738	6/
Rate LDS - Large Distribution Service									
Customer Charge:									
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,300.00	-	-		-	0.00	1,300.00	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,300.00	-	-		-	0.00	2,300.00	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,800.00	-	-		-	0.00	4,800.00	
Annual Throughput > 7,500,000 thm	$	7,400.00	-	-		-	0.00	7,400.00	
Usage Charge:									
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.11359	-	-	5/	-	0.00000	0.11359	6/
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.09982	-	-	5/	-	0.00000	0.09982	6/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.08263	-	-	5/	-	0.00000	0.08263	6/
Annual Throughput > 7,500,000 thm	$	0.04800	-	-	5/	-	0.00000	0.04800	6/

1/ Please see Page 21a for rate components.
2/ Please see Page 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
4/ If a customer transfers to LGSS from SDS or LDS, the Gas Cost Adjustment shall not be billed for twelve billing cycles.
5/ If a customer transfers to SDS or LDS from LGSS, the Gas Cost Adjustment shall be billed for twelve billing cycles.
6/ Plus Rider EBS Option 1 or 2 - See Page 21.

Rate Summary

Rate per thm

Main Line Service Rate Schedules Commercial / Industrial		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Total Effective Rate
Rate MLSS - Main Line Sales Service							
Customer Charge:							
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34	-	-	-	0.00	469.34
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00	-	-	-	0.00	1,149.00
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00	-	-	-	0.00	2,050.00
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00	-	-	-	0.00	4,096.00
Annual Throughput > 7,500,000 thm	$	7,322.00	-	-	-	0.00	7,322.00
Usage Charge:							
MLS Class I Annual Throughput > 274,000 thm	$	0.00936	0.31653	(0.03547) 4/	0.12544	0.00000	0.41586
MLS Class II:							
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04474	0.31653	(0.03547) 4/	0.12544	0.00000	0.45124
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03869	0.31653	(0.03547) 4/	0.12544	0.00000	0.44519
Annual Throughput > 7,500,000 thm	$	0.03351	0.31653	(0.03547) 4/	0.12544	0.00000	0.44001
Rate MLDS - Main Line Distribution Service							
Customer Charge:							
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34	-	-	-	0.00	469.34
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00	-	-	-	0.00	1,149.00
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00	-	-	-	0.00	2,050.00
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00	-	-	-	0.00	4,096.00
Annual Throughput > 7,500,000 thm	$	7,322.00	-	-	-	0.00	7,322.00
Usage Charge:							
MLS Class I Annual Throughput > 274,000 thm	$	0.00936	-	-	-	0.00000	0.00936 6/
MLS Class II:							
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04474	-	- 5/	-	0.00000	0.04474 6/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03869	-	- 5/	-	0.00000	0.03869 6/
Annual Throughput > 7,500,000 thm	$	0.03351	-	- 5/	-	0.00000	0.03351 6/

1/ Please see Page 21a for rate components.
2/ Please see Page 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
4/ If a customer transfers to MLSS from MLDS, the Gas Cost Adjustment shall not be billed for twelve billing cycles.
5/ If a customer transfers to MLDS from MLSS, the Gas Cost Adjustment shall be billed for twelve billing cycles.
6/ Plus Rider EBS Option 1 or 2 - See Page 21.

Other Rates Summary

Rate per thm

Description		Rate $/ thm	Applicable Rate Schedules
Tennessee Gas Pipeline Company Refund	$	-	SGSS
TCO Modernization Refund- Settlement - Residential	$	0.00080	RSS/RDS
TCO Modernization Refund-Settlement - Non-Residential	$	0.00114	SGSS/SGDS/SCD/LGSS/MLSS
Price to Compare for Residential Gas Supply	$	0.31590	RSS
Price to Compare for Commercial Gas Supply	$	0.31284	SGSS (< = 64,400 thms)
State Tax Adjustment Surcharge Percentage		0.00000%	Customer and Distribution Charges on all rates
Rate SS - Standby Service	$	0.76941	Per therm based on a customer's Maximum Daily Firm Requirement. See Pages 134 - 136 herein for detail.

Rider Summary

Rate per thm

Riders		Rate $/ thm	Applicable Rate Schedules
Customer Choice - Rider CC	$	0.00009	RSS/RDS/SGSS/SGDS/SCD/DGDS
Universal Service Plan - Rider USP	$	0.07420	RSS/RDS
Distribution System Improvement Charge - Rider DSIC		0.00000%	This percentage is applied to a portion of the Distribution Charge and the Customer Charge. See Pages 177-180 for Rider DSIC details.
Elective Balancing Service - Rider EBS:			
Option 1 - Small Customer	$	0.01626	SGDS/SDS
Option 1 - Large Customer	$	0.00656	LDS/MLDS
Option 2 - Small Customer	$	0.00697	SGDS/SDS
Option 2 - Large Customer	$	0.00226	LDS/MLDS
Gas Procurement Charge - Rider GPC	$	0.00695	RSS/SGSS/LGSS/MLSS
Merchant Function Charge - Rider MFC	$	0.00464	RSS
Merchant Function Charge - Rider MFC	$	0.00158	SGSS
Purchased Gas Cost - Rider PGC		Pg. 21a & 21b	Rate Schedules specified on Page 21a & 21b

Gas Supply Charge Summary

Rate per thm

Rate Schedule		PGCC	Rider GPC	Rider MFC	Total Gas Supply Charge
Rate CAP - Customer Assistance Plan	$	-	-	-	-
Rate RSS - Residential Sales Service	$	0.30958	0.00695	0.00464	0.32117
Rate SGSS - Small General Sales Service	$	0.30958	0.00695	0.00158	0.31811
Rate LGSS - Large General Sales Service	$	0.30958	0.00695	-	0.31653
Rate MLSS Main Line Sales Service	$	0.30958	0.00695	-	0.31653

Pass-through Charge Summary
Rate per thm

Rate Schedule		PGDC	PGDC "E" Factor	Capacity Assignment Factor	Pipeline Refund	Rider CC	Rider USP	Total Pass-through Charge
Rate CAP - Customer Assistance Plan	$	0.12753	(0.00323)	(0.03020)	0.00080	-	-	0.09490
Rate RSS - Residential Sales Service	$	0.12753	(0.00323)	-	0.00080	0.00009	0.07420	0.19939
Rate SGSS - Small General Sales Service	$	0.12753	(0.00323)	-	0.00114	0.00009	-	0.12553
Rate LGSS - Large General Sales Service	$	0.12753	(0.00323)	-	0.00114	-	-	0.12544
Rate MLSS Main Line Sales Service	$	0.12753	(0.00323)	-	0.00114	-	-	0.12544
Rate RDS - Residential Distribution Service	$	0.12753	(0.00323)	(0.03020)	0.00080	0.00009	0.07420	0.16919
Rate SCD - Small Commercial Distribution (Choice)	$	0.12753	(0.00323)	(0.03020)	0.00114	0.00009	-	0.09533
Rate SGDS - Small General Distribution Service								
Priority One (P1)	$	0.12753	(0.00323)	-	0.00114	0.00009	-	0.12553
Non-Priority One (NP1)		-	-	-	-	-	-	-
Rate SDS - Small Distribution Service	$	-	-	-	-	-	-	-
Rate LDS - Large Distribution Service	$	-	-	-	-	-	-	-
Rate MLDS - Main Line Distribution Service	$	-	-	-	-	-	-	-

Price-to-Compare (PTC) Summary
Rate per thm

Customer Class		PGCC	Gas Cost Adjustment	Capacity Assignment Factor	Rider GPC	Rider MFC	Total Price-to-Compare
Residential	$	0.30958	(0.03547)	0.03020	0.00695	0.00464	0.31590
Commercial < = 64,400 thm/year	$	0.30958	(0.03547)	0.03020	0.00695	0.00158	0.31284

RIDER PGC - PURCHASED GAS COST

PROVISIONS FOR RECOVERY OF PURCHASED GAS COSTS

RIDER PGC APPLICABLE TO SALES SERVICE CUSTOMERS

Rates for each thm of gas supplied to sales customers subject to this Rider under the Rate RSS, Rate SGSS, Rate LGSS, and Rate MLSS rate schedules shall include $0.39841 per thm for recovery of purchased gas costs. (I) (D) This rate includes the commodity cost component (CC) of $0.30958 per thm, the commodity "E" Factor component (CE) of ($0.03547) per thm, the demand cost component (DC) of $0.12753 per thm, and the demand "E" Factor component of ($0.00323) per thm.

RIDER PGC APPLICABLE TO SGDS PRIORITY ONE CUSTOMERS

Rates for each thm of gas distributed under the Rate SGDS rate schedules for Priority-One Service customers (D) shall include $0.12430 per thm for recovery of Purchased Gas Demand Costs (PGDC). This rate includes the DC of $0.12753 per thm and the demand "E" Factor component of ($0.00323) per thm.

RIDER PGC CHARGED TO CHOICE DISTRIBUTION SERVICE CUSTOMERS

Rates for each thm of gas distributed under Rate RDS and Rate SCD shall include $0.09410 per thm for (D) recovery of Purchased Gas Demand Costs. This rate includes the DC of $0.12753 per thm, the Capacity Assignment Factor (CAF) of ($0.03020) per thm and the DC "E" Factor component of ($0.00323) per thm. The CAF represents costs not assignable to Choice Distribution Service customers.

Such rates shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's Regulations, to reflect changes in the level of purchased gas costs, as calculated in the manner set forth below.

PRESENTATION ON CUSTOMER BILLS

For sales service customers served under Rate RSS, Rate SGSS, Rate LGSS and Rate MLSS, the Pass-through (D) (I) Charge includes the PGDC of $0.12753 per thm plus the demand "E" Factor of ($0.00323) per thm. The two factors total $0.12430 per thm. The Gas Supply Charge includes the PGCC of $0.30958 per thm. The Gas Cost Adjustment is the commodity "E" Factor of ($0.03547) per thm.

For General Distribution Service customers served under Priority-One Rate SGDS, the Pass-through Charge includes the PGDC of $0.12753 per thm and the demand "E" Factor component of ($0.00323) per thm, totaling (D) $0.12430 per thm.

For Choice Distribution Service customers served under Rate RDS or Rate SCD, the Pass-through Charge includes the PGDC of $0.12753 per thm, the CAF of ($0.03020) per thm and the demand "E" Factor component (D) of ($0.00323) per thm, all of which total $0.09410 per thm.

QUARTERLY UPDATES

The Company's rates for recovery of purchased gas costs are also subject to quarterly adjustments under procedures set forth in the Commission's regulations at 52.Pa. Code § 53.64 (i) (5). Such updates shall reflect, in addition to the provisions of the regulation, adjustments to the projected commodity cost of purchased gas based upon more current versions of the same sources of data and using the same methods to project the commodity cost of purchased gas approved by the Commission in the Company's most recent annual proceeding for recovery of purchased gas costs under section 1307(f) of the Public Utility Code.

(D) Indicates Decrease (I) Indicates Increase

RIDER PGC - PURCHASED GAS COST (Continued)

COMPUTATION OF PURCHASED GAS DEMAND COSTS PER THM – Continued

Supplier refunds that are not included in "CE" will be included in the calculation of "DE" with interest added at the annual rate of six percent (6%) calculated from the month received to the effective month such refund is refunded. The period over which such refunds will be made shall be established by the Commission.

"S" - projected thms of gas to be billed to customers under the distribution charges of the Rate RSS, Rate SGSS, Rate LGSS, and Rate MLSS rate schedules plus the projected thm of gas to be distributed to customers under Rate RDS, Rate SCD and SGDS Priority One Distribution rate schedules of this Tariff during the period when rates will be in effect.

PROVISION OF PURCHASED GAS DEMAND COST CREDIT DUE TO CUSTOMERS ELECTING CHOICE DISTRIBUTION SERVICE – CAPACITY ASSIGNMENT FACTOR (CAF) (D)

The Purchased Gas Demand Cost (PGDC) rate included in the Pass-through Charge billed to Choice Distribution Service customers served under Rate RDS or Rate SCD shall be $0.09410 per thm. Such rate shall be equal to the PGDC component of $0.12430 per thm as calculated above, less the CAF of $0.03020 per thm. The CAF shall be equal to the projected annual cost of assigned Firm Capacity less estimated annual storage commodity costs (storage injection, withdrawal, shrinkage and commodity transportation cost) with the net divided by the estimated, normalized annual usage of customers electing Choice Distribution Service. The CAF of $0.03020 per thm representing costs not assignable to CHOICE customers shall be included in the Price-to-Compare.

DETERMINATION OF OVER/UNDERCOLLECTION OF GAS COSTS

Commodity E-factor

In computing the experienced over/under collection of purchased gas commodity costs for a period defined by the Commission, the following procedure shall be used:

(a) All experienced purchased gas commodity costs actually incurred by the Company to service customers pursuant to all rate schedules of this Tariff.

Experienced purchased gas commodity costs shall include, but not be limited to, the following:

(1) payments to suppliers to accept assignment of capacity on interstate pipelines other than Columbia Gas Transmission Corporation to the extent permitted under the Rules Applicable to Distribution Service;

(2) costs paid for employing futures, options and other risk management tools, including but not limited to, supplier related costs associated with the fixed price contracts or financial contracts utilized by the Company to lessen the impact of price volatility for PGC customers; and

(3) the index price of gas purchased from distribution customers under the provisions of the Deliveries in Excess of Consumption section of Paragraph 3 of the Rules Applicable to Distribution Service.

(D) Indicates Decrease (I) Indicates Increase