Columbia Exhibit No.

BEFORE
THE PUBLIC UTILTIES COMMISSION OF OHIO

In the Matter of the Joint Motion to Modify the December 2, 2009 Opinion and Order and the September 7, 2011 Second Opinion and Order in Case No. 08-1344-GA-EXM.	)))))	Case No. 12-2637-GA-EXM

PREPARED DIRECT TESTIMONY OF
MICHAEL D. ANDERSON
ON BEHALF OF COLUMBIA GAS OF OHIO, INC.

Stephen B. Seiple, Asst. General Counsel
(Counsel of Record)
Brooke E. Leslie, Counsel
200 Civic Center Drive
P. O. Box 117
Columbus, Ohio 43216-0117
Telephone: (614) 460-4648
(614) 460-5558
Fax: (614) 460-6986
Email: sseiple@nisource.com
bleslie@nisource.com

Daniel R. Conway
Eric B. Gallon
Mark S. Stemm
Porter Wright Morris & Arthur LLP
Huntington Center
41 South High Street
Columbus, Ohio 43215
Telephone: (614) 227-2270
(614) 227-2190
(614) 227-2092
Fax: (614) 227-2100
Email: dconway@porterwright.com
egallon@porterwright.com
mstemm@porterwright.com

Attorneys for
COLUMBIA GAS OF OHIO, INC.

November 12, 2012

PREPARED DIRECT TESTIMONY OF MICHAEL D. ANDERSON

Q: Please state your name and business address.

A: My name is Michael D. Anderson. My business address is Post Office Box 117, 200 Civic Center Drive, Columbus, Ohio 43216-0117.

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

A: I am employed by NiSource Corporate Services. My current title is Director, Supply Development.

Q: What are your responsibilities as Director, Supply Development?

A: As Director, Supply Development, my principal responsibilities include negotiation of pipeline capacity contracts; participation in FERC related matters and evaluation, analysis and development of potential non-traditional supply options including such diverse items as landfill gas projects and commercial opportunities to connect developing shale gas resources to the Columbia's distribution system. I also provide internal education to NiSource employees and external audiences on the impacts of new supply resources, principally those derived from shale formations. These services and responsibilities are performed on behalf of Columbia and Columbia's local distribution affiliates in Kentucky, Pennsylvania, Maryland, Virginia and Massachusetts.

Q: What is your educational background?

A: I received a Bachelor of Science degree in Fuels Engineering from the University of Utah in 1978. The Fuels Engineering curriculum consisted primarily of Chemical Engineering studies with specific emphasis on engineering analysis of conventional and synthetic fuel resources.

Q: Please briefly describe your professional experience.

A: I have been employed by Columbia since 1990, initially as Manager of Supply Planning, advancing to Manager of Economic Analysis in 1993. On May 1, 1997, I was promoted to Director, Supply Planning and on May 1, 2010 named Director, Supply Development. From 1982 through 1990 I was employed as Petroleum Engineer, Engineering Manager and Manager of Gas Supply for various subsidiaries of Texas Eastern Corporation ("Texas Eastern"). In the engineering positions I was responsible for the drilling and production department of Texas Eastern's Rocky Mountain exploration and production operations, with direct responsibilities including economic analysis, justification and management of drilling prospects, production operations and in-field gas gathering/treating projects. In the position of Manager of Gas Supply I was responsible for the analysis and negotiation of new gas supplies for system supply use and the renegotiation of existing gas supply contracts to reduce contractual obligations to purchase gas supplies for system supply use under take-or-pay contracts. From 1978 until 1982 I was employed by Marathon Oil and J. M. Huber Corporation as a Petroleum Engineer in the Permian Basin of West Texas and Southeast New Mexico.

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

A: My testimony will discuss Columbia's distribution network, Columbia's capacity portfolio, CHOICE/SCO Balancing services and fee, Columbia's Off-System Sales and Capacity Release Incentive program and Shale gas issues. Additionally, I will briefly discuss Columbia's Design Peak Day demand and capacity balance, the allocation procedure employed by Columbia for capacity assignment to CHOICE and SCO suppliers, and the Stipulation timeline.

<u>COLUMBIA'S DISTRIBUTION NETWORK</u>

Q: Please describe Columbia's distribution network.

A: Columbia's distribution network consists of several hundred, often isolated distribution systems spread out over Columbia's 60 Ohio county service territory. These distribution systems are served by over 840 separate points of delivery ("POD") from upstream interstate pipeline companies often with a single POD serving a single distribution system. In addition to the identified PODs, Columbia also provides service to over 10,000 mainline tap customer locations throughout Ohio.

Q: How does Columbia's distribution network compare to other Ohio LDCs?

A: Columbia's distribution network is significantly more complex. For example, Dominion East Ohio Gas ("DEOG"), the next largest Ohio LDC, receives service from interstate pipelines from approximately 35 PODs while Vectren Energy Delivery of Ohio ("Vectren") receives service from interstate pipelines at approximately 12 PODs. The number of PODs with interstate pipelines that Columbia must manage exceeds the total of Vectren and DEOG by a factor of almost 18. In addition, Columbia, Vectren and DEOG receive service from Columbia Gas Transmission, LLC ("TCO"). Both Vectren and DEOG receive service through a single Pipeline Scheduling Point ("PSP") while Columbia must manage the receipts of service through twelve PSPs. Columbia's supply pipeline configuration and geographic spread add a level of complexity to its operations. This conclusion is supported in the Liberty Consulting Group's "Final Report, Management/Performance Audit, Columbia Gas of Ohio, Inc., Case No. 08-221-GA-GCR".[1] Columbia's broad service territory, including a dozen market areas[2] and a large number of receipt points, and the integration of the Columbia system with the TCO pipeline create a more complex operating environment compared to most LDCs. Liberty Consulting Group agreed with this characterization of mine as well.

Q: Does Columbia own any high-pressure transmission lines that interconnect these wide-spread distribution systems?

A: No.

Q: Earlier you stated that most of these isolated distribution systems are connected to only a single POD and therefore a single pipeline, are all these isolated distribution systems connected to the same pipeline?

A: No. However, the vast majority are connected to TCO.

Q: For those distribution systems or markets connected to TCO do they have alternative upstream pipeline options?

A: For the vast majority of those markets no alternate pipeline options exist.

Q: In what markets does Columbia have alternate pipeline options?

A: Alternate pipeline options presently exist for Columbia's Maumee market which serves the west side of Toledo; portions of the south side of Columbia's Columbus market; portions of Columbia's Parma market; portions of Columbia's Findlay market; and Columbia's markets in Fostoria, Oberlin, and Norwalk. I should note that Columbia has several markets or portions of markets where service from TCO is not available. These markets generally do not have alternatives to the service utilized to provide supplies to these markets. These markets generally are served through either Columbia's contract with Gatherco or with supplies delivered from DEOG either through direct purchase by Columbia or under an exchange agreement with DEOG.

Q: Please describe those alternative pipeline options.

A: For the Maumee market Columbia has the ability to receive gas from ANR Pipeline Company ("ANR") and Panhandle Eastern Pipe Line Company, LP

[1] Final Report, Management/Performance Audit, Columbia Gas of Ohio, Inc., Case No. 08-221-GA-GCR", Liberty Consulting Group at III-11.

[2] Market Areas are referred to as Pipeline Scheduling Points or PSPs in Columbia's tariff and Program Outline

("Panhandle"). Columbia presently contracts for capacity to serve this market from Panhandle. For the Columbus market Columbia has the ability to receive gas from Dominion Transmission, Inc. ("DTI") and Texas Eastern Transmission, LP. ("Texas Eastern"). Columbia does not currently contract for capacity from either of these pipelines. For the Parma market Columbia has the ability to receive gas from North Coast Gas Transmission, LLC. ("North Coast") at two PODs. Columbia presently contracts for capacity from North Coast at both these locations. For the Findlay, Fostoria, Oberlin and Norwalk markets Columbia has the ability to receive gas from North Coast. Columbia presently contracts for service from North Coast in all these markets.

Q: Does Columbia have any other non-pipeline capacity resources?

A: Yes, Columbia has: (a) a peaking contract provided by J. P. Morgan Ventures Energy Corporation which provides service to our Parma market, (b) a full requirements contract with Gatherco, Inc. that serves numerous Columbia markets, (c) local gas supply contracts with Producer's Gas Sales, Inc. ("Producer's") that serve portions of Columbia's markets in Coshocton, Zanesville and Newark and (d) numerous local gas contracts with small gas producers.

Q: Please describe the purchases and exchange agreement with DEOG.

A: Columbia purchases supplies delivered by DEOG into its Brewster market. While portions of this market are served by TCO, it is cheaper for Columbia to acquire supplies delivered by DEOG rather than invest capital into its distribution system and increase capacity on TCO to serve this portion of the Brewster market. The exchange agreement between Columbia and DEOG enable both parties to serve certain markets in a manner than minimizes costs for both. Under this agreement DEOG will deliver supplies into certain Columbia markets and Columbia will deliver supplies into certain DEOG markets. This "exchange" of deliveries is performed on a volumetric basis and enables both companies to avoid constructing additional distribution facilities to markets that are removed from the respective company's existing distribution system.

Q: Please describe Columbia's agreement with Gatherco.

A: Columbia's agreement with Gatherco provides service to a large number of markets served off of gathering and small transmission lines that Gatherco purchased from TCO approximately 15 years ago. The contract with Gatherco provides service through approximately 80 PODs and is considered a "full requirements" contract. Stated differently, this contract with Gatherco is a no-notice contract that serves all Columbia customer demand behind each POD each day of the year without prior scheduling. A large portion of the supply Gatherco utilizes to provide service to Columbia comes from local gas supplies.

Q: Are the PODs at which Gatherco provides service to Columbia included in the 840 PODs noted earlier?

A: No, they are in addition to these PODs.

Q: Please describe Columbia's agreement with Producer's.

A: On a monthly basis Columbia nominates a volume to be delivered by Producers to interconnections between Producer's and Columbia in Coshocton, Newark and Zanesville. Without these supplies Columbia would need to spend capital to expand/uprate its distribution system in these markets and increase upstream capacity on TCO.

COLUMBIA'S CAPACITY PORTFOLIO

Q: Please describe briefly Columbia's capacity portfolio.

A: Attachment A provides a current listing of Columbia's capacity portfolio.

Q: Please describe the importance of the TCO capacity to Columbia.

A: The TCO capacity is critical to the provision of reliable, economic service to Columbia's customers. As I noted earlier, TCO capacity provides the only available service to the vast majority of Columbia's markets. Furthermore, given the large number of PODs, diverse service territory and the temperature-sensitive demand of the vast majority of customers that Columbia contracts for capacity to serve; the TCO capacity provides the most efficient, cost effective means to serve its customers. Additionally, Columbia retains the ultimate responsibility through its role as supplier of last resort. Given the items noted above among others, Columbia is not able to reliably provide this vital service without contracting for this capacity.

Q: Please describe Maximum Daily Delivery Obligations and Daily Delivery Quantities.

A: Maximum Daily Delivery Obligations ("MDDO") define the maximum quantity of gas that the upstream pipeline must deliver, upon demand, to any POD on any day that an operational restriction has not been issued by that pipeline. Columbia manages the allocation of its MDDOs based on the total size of its downstream market behind each POD. Such allocation simplifies the ability of Columbia and its shippers to manage the daily delivery of gas scheduled at 12 PSPs to over 840 interstate pipeline PODs. Daily Delivery Quantities ("DDQ") define the upstream pipeline's delivery obligation to an individual POD on all days including days when the pipeline has issued operational restrictions. DDQs are critical to the design of upstream facilities serving individual PODs to ensure that firm service can be maintained.

Q: **Please describe the relationship between MDDOs and DDQ with Columbia's contracts with TCO.**

A: Reaching back to the Federal Energy Regulatory Commission's ("FERC") restructuring of the interstate pipeline system under Order 636, TCO's transportation service contracts, both Firm Transportation Service ("FTS") and Storage Service Transportation ("SST"), were allocated MDDO and DDQ levels in excess of their daily contract entitlements. These excess MDDO and DDQ levels are grand fathered to Columbia's existing FTS and SST contracts. Any reduction in these contracts results in a proportional reduction in these grandfathered MDDO and DDQ rights and system flexibility.

Q: **Are replacement contracts granted these grand fathered MDDO and DDQ rights?**

A: To the extent that Columbia extends or renews its existing FTS and SST contracts the grandfathered MDDO and DDQ rights stay intact. However, if Columbia terminates capacity under these contracts and either: (a) later recontracts for the capacity, or, (b) other parties contract for the capacity, the grandfathered MDDO and DDQ rights are lost. If no one recontracts for this capacity then the MDDO and DDQ rights are no longer in force and the contractual obligation of the pipeline to provide associated firm service are terminated.

Q: **Why are these grandfathered MDDO and DDQ important?**

A: They are critical on a number of levels to the operation of Columbia's distribution system and for the services Columbia offers to its customers and their suppliers. Below I have listed a few of those areas in which grandfathered MDDOs and DDQs play a critical role:

a. Ability to manage delivery of supplies to individual PODs that are scheduled at the PSP level. Suppliers for CHOICE, SCO and Transportation Service ("TS") customers all must schedule gas to the PSP in which their customers reside. This is a far simpler, more efficient and lower cost option then scheduling to individual PODs.

b. Ability to manage shifting customer demands. Customer demands behind individual PODs are constantly changing driven by a number of factors including conservation efforts, addition or deletion of building stock, etc. The grandfathered MDDOs and DDQs enable Columbia to efficiently manage this dynamic. Given Columbia's wide-spread service territory, the large number of PODs and the dynamic nature of customer demand. These grandfathered MDDOs and DDQs enable Columbia to keep pipeline entitlements at levels essentially equivalent to its design peak day demand to assure reliability of service.

c. The grandfathered MDDOs and DDQs enable Columbia to operate CHOICE and SCO programs on a level playing field basis. Without these grandfathered MDDOs and DDQs, the assignment of capacity to CHOICE and SCO suppliers would be significantly different and would vary by PSP. An assignment of capacity that varies by PSP would increase complexity, reduce operational efficiency and increase costs for both SCO and CHOICE customers. Grandfathered MDDOs and DDQs provide Columbia the ability, through the inherent additional system flexibility they provide, to assign capacity by capacity type, i.e. FTS and storage, on an equal basis to all PSPs making the delivery and management of supplies under the CHOICE and SCO programs more efficient and therefore less expensive.

d. The grandfathered MDDOs and DDQs enable Columbia to provide a uniform balancing service to CHOICE and SCO suppliers in all PSPs.

e. The grandfathered MDDOs and DDQs enable Columbia's TS customers and their suppliers the added flexibility to acquire their capacity needs at the PSP level and not to specific PODs. They also enable Columbia to provide an interruptible banking and balancing service to all PODs. These services provide TS customers with a lower cost alternative regarding the acquisition of their energy supplies keeping their costs lower and preserving jobs and economic activity for the benefit of all Ohioans. It should be noted that Columbia does not acquire nor retain capacity to provide this interruptible banking and balancing service. The service is provided on a day-to-day basis from the temporarily unused component of the no-notice capacity Columbia retains to provide balancing services to CHOICE and SCO suppliers. On days when Columbia anticipates that it will not have the ability to balance TS customers' supply and demand it will restrict the interruptible banking and balancing service as needed.

f. Columbia's ability to serve as supplier of last resort.

Q: Please describe the importance of Columbia's capacity with Columbia Gulf?

A: On a contractual basis the Columbia Gulf capacity provides a majority of the supplies delivered to Columbia's CHOICE and SCO customers. However, more importantly, on a physical basis a majority of the gas that is consumed by Columbia's customers originates in the Gulf Coast region and is transported by Columbia Gulf to TCO and on TCO into Ohio.

Q: Please describe in more detail how supplies are physically delivered to Columbia's customers.

A: As noted earlier the vast majority of Columbia's markets are served by TCO with approximately 92%[3] of all supplies received by Columbia delivered to its distribution system by TCO. The majority of the gas supplies consumed by Columbia customers are received by TCO from Columbia Gulf. These supplies provide the primary source of gas injected into TCO's southern Ohio storage fields. Additionally, these supplies coupled with supplies received by TCO at Lebanon, from Rockies Express ("REX") at Fairfield and at Maumee are utilized to fill Columbia's northern Ohio storage fields. In the winter these storage supplies provide a significant percentage of the physical supplies consumed by Columbia's customers. Without supplies delivered by Columbia Gulf, TCO would not be able to fill the Ohio storage fields that are critical to Columbia's ability to provide reliable service to its customers. This criticality is cited by the fact that Columbia's daily storage delivery rights under TCO's FSS Rate Schedule represent 74% of the supply needed to meet Columbia's design peak day demand; which rights cannot be placed at risk due to the inability to fill Ohio storage fields.

Q: Can Appalachian Basin shale gas be used in lieu of Columbia Gulf delivered supplies?

A: With the possible limited exception of small Columbia markets in the Ohio River valley area, shale gas supplies do not physically flow on TCO's system to a point where they can be delivered into the majority of Columbia's markets, including injection into storage.

Q: TCO has recently closed an open season on their Westside Expansion Project. Please describe this project.

[3] Based on twelve months ending July 2012.

A: The Westside Expansion Project consists of modifications to the TCO system that will enable Marcellus Shale gas supplies produced in southwest Pennsylvania and northern West Virginia to be transported to the Gulf Coast region.

Q: Can Columbia rely on these supplies to displace Columbia Gulf?

A: No, it is our understanding that the Westside Expansion shippers have a contractual right to ship gas from their receipt points in Pennsylvania and West Virginia to the Gulf Coast region. In fact, TCO has announced that it plans on physically reconfiguring one of the Columbia Gulf pipelines in association with the Westside Expansion Project to send gas south. Thus, Columbia cannot assume that these supplies would be available to purchase at Leach, KY[4] when the shippers have the contractual ability to deliver these supplies to the Gulf Coast. I will address shale gas issues in further detail later in my testimony.

Q: How does the extension of Columbia's interstate pipeline contracts impact competition?

A: I do not believe that the renewal of Columbia's interstate pipeline capacity contracts has any adverse impact upon competition, to the contrary Columbia's renewal enhances competition through lowering barriers to entry, reducing supplier uncertainty, and preserving reliability. As discussed herein Columbia's capacity is critical to the preservation of service to Columbia's customers. While consumer advocates typically represent only a single class of customers, or a portion of a single class, Columbia must manage and operate a system for the benefit of all customers. I have discussed how Columbia's capacity portfolio does just that. In the vast majority of Columbia's markets this capacity portfolio provides the only available service. Shale gas supplies cannot provide an alternative to these markets. The interstate capacity Columbia holds are contracted for at or below FERC approved rates. Renewal of the contracts at the levels specified in the Stipulation is necessary for Columbia to maintain service reliability across its highly complex, widespread service territory.

Q: In its Comments filed in this docket OPAE claims that interstate pipelines were the first component of the natural gas supply system to be deregulated. Do you agree with this assertion?

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[4] Leach, KY is the name of the primary interconnection between Columbia Gulf and TCO.

A: No I do not. Interstate pipelines remain heavily regulated by FERC. While FERC may have removed the interstate pipelines' prior commodity sales responsibility, that is not deregulation. The only component of the natural gas supply system that is deregulated is the production component of the system.

Q: Is Columbia proposing any changes to any of the contracts in the Joint Stipulation and Recommendation filed in this case?

A: Yes, Columbia will be terminating the peaking contract provided by J. P. Morgan Ventures Energy Corporation and a portion of the North Coast contract along the associated Crossroads Pipeline Company ("Crossroads") capacity that serves Columbia's Findlay, Fostoria, Oberlin and Norwalk markets. Additionally, Columbia has proposed to reduce its contract quantity on Columbia Gulf effective April 1, 2016 by 25%.

Q: Why is Columbia terminating or reducing these capacity volumes?

A: Columbia is terminating the J.P. Morgan and North Coast/Crossroads capacities for several reasons. The primary reason is to bring Columbia's city gate capacity portfolio in line with its design peak day forecast. Additionally, the capacity Columbia is terminating provides capacity that is not operationally required; other capacity exists in these same markets. Furthermore, these contracts are less operationally efficient, or in other words are more costly per Dth of seasonal/annual capacity and/or are more expensive than competing alternatives. Columbia is proposing to reduce its Columbia Gulf Contract by 25% in 2016 as a means to test whether Appalachian Basin shale gas supplies can be relied upon to meet the physical needs of Columbia's customers. As I note later in my testimony this is not currently a reality.

Q: Has Columbia conducted any recent evaluations of alternate pipeline capacity options to serve its existing service territory?

A: Yes, pursuant to the Joint Stipulation and Recommendation in Case No. 08-221-GA-GCR and Case No. 07-221-GA-FOR Columbia performed an analysis of potential pipeline capacity and peaking options for markets that have a firm design day demand of 50,000 Dth or greater. In this analysis Columbia identified five PODs that served markets with firm design day demand of 50,000 Dth or greater that are accessible by alternate pipelines and evaluated potential service options from five interstate pipelines with the ability to serve these locations. Additionally, Columbia expanded this evaluation beyond that required by the Joint Stipulation and Recommendation in Case No. 08-221-GA-GCR and Case No. 07-221-GA-FOR to include a number of smaller markets that a facilities analysis indicated were within a reasonable distance to consider for this evaluation. This expanded analysis added a sixth interstate pipeline into the evaluation. Additionally, Columbia evaluated potential peaking options for service to eleven markets with firm design day demand of 50,000 Dth or greater.

Q: Please describe briefly how Columbia performed this analysis.

A: Columbia evaluated the firm service options by first performing an analysis based on 100% load factor utilization and using that as a screening tool. This is a valid screening tool as options that are not competitive on a 100% load factor basis are generally less competitive at lower load factors. These evaluations were compared against Columbia's primary service options of Columbia Gulf/TCO for firm transportation service and Columbia Gulf/ TCO FTS/TCO FSS-SST for storage. This initial screening evaluation indicated three FTS options and one storage option were possibly lower cost alternatives to Columbia's existing services. Columbia next evaluated what, if any, capital costs would be necessary to connect the respective pipeline to the corresponding Columbia market. Including these capital costs eliminated one of the FTS options from further consideration. Of the remaining options, one of the FTS options was competitive against Columba's existing service from Panhandle and will be further evaluated upon termination of the Panhandle contracts. The remaining two options were for service from DTI into Columbia's Southern Supply Line feeding the southern portion of the Columbus market. Columbia then approached DTI to seek a proposal for service into this location, but was informed by DTI that it had no available capacity at that location.

PEAK DAY FORECAST AND SUPPLY BALANCE

Q: Earlier you noted that Columbia was terminating a portion of its capacity portfolio to bring its portfolio in line with its design peak day demand. Please provide a brief overview of Columbia's design peak day demand.

A: Annually, Columbia develops a document known as its Peak Day Forecast for supply planning and operational purposes. This forecast analyses customer demands and forecasts design day demand for both firm and non-firm customers five years into the future.

Q: What is the significance between firm and non-firm customers?

A: From a capacity planning perspective the demand of firm customers serves as the basis for Columbia's contracts for capacity/firm city gate resources to ensure reliable service. This is service to residential and small commercial and industrial customers who do not qualify for, or chose to take service under the Company's TS program. With the exception of requests for Columbia to provide Backup Service, Columbia does not contract for capacity to serve non-firm demand. Non-firm customers are those larger commercial and industrial customers and those customers that have been grandfathered into Columbia's TS program.

Q: What is Columbia's current forecast of design peak day demand?

A: Columbia's most recent Peak Day Forecast projects design peak day demand for the 2013-14 winter of 1,948,900 Dth. This is comprised of 1,922,400 Dth of firm demand and 26,500 Dth of Backup Service requests.

Q: How does this forecast compare to Columbia's capacity portfolio for the 2013-14 winter season?

A: As noted in the Stipulation, Columbia anticipates having a total of 1,940,214 Dth of firm peak day capacity and firm city gate supply. However, Columbia plans on using 11,500 Dth for assignment to TS customers leaving 1,928,714 Dth to provide the aforementioned Backup Service requests and for utilization in the CHOICE/SCO programs. I will discuss the assignment of capacity to CHOICE and SCO suppliers later in my testimony.

Q: Does Columbia's latest Peak Day Forecast indicate Columbia has excess capacity?

A: No. On the contrary, Columbia latest Peak Day Forecast shows firm demand that slightly exceeds its available firm capacity entitlements by 20,186 Dth or 1.05%.

Q: Is Columbia's capacity portfolio, as set forth in the Stipulation, necessary to provide service?

A: Yes. As noted above, all the capacity is needed to meet projected demands. As for the price of the capacity, all of the capacity that Columbia contracts for from interstate pipelines is priced either at or below the maximum FERC authorized tariff rates. Thus, the rates for this capacity have been approved by the FERC. To the extent other parties may claim that the SCO is a market-based rate established through an open auction process that has been very successful in providing Ohioans with a low-priced option for natural gas this success has been achieved with essentially the same capacity portfolio as Columbia sets forth in this case. Accordingly, it supports the reasonableness of that capacity portfolio.

Q: How does Columbia forecast the design peak day demand to change in the future?

A: Columbia's Peak Day Forecast projects design day demand through the winter of 2016-17. The most recent Peak Day Forecast shows slight growth in design peak day demand of approximately 0.5% annually.

Q: Has Columbia's peak day forecasting process been reviewed by any outside party?

A: Yes, Columbia's peak day forecasting process has been reviewed by numerous outside parties including the auditors hired by the Commission to perform past GCR Management Performance Audits.

Q: What have been the findings of these auditors?

A: Generally the auditors have found Columbia's process to be rigorous and consistent with industry practice. In its "Report on the Management/Performance Audit of the Gas Purchasing Practices and Policies of Columbia Gas of Ohio", in Case No. 05-221-GA-GCR, McFadden Consulting Group, Inc. stated, "The Company's peak day demand forecasting is highly developed."[5] Furthermore, McFadden found "The peak day forecast is reasonable and consistent with industry practice" and "The Company has developed models that accurately forecast its demand requirements." In Columbia's last GCR audit in Case No. 08-221-GA-GCR, the Auditor, The Liberty Consulting Group, suggested a few minor changes to Columbia's process. However, upon detailed review by Columbia much of those suggested changes were found to be long standing Columbia practices.

CAPACITY ALLOCATION PROCESS

Q: Please describe the capacity allocation process Columbia utilizes to assign capacity to CHOICE and SCO suppliers.

A: After Columbia retains adequate storage to provide necessary system balancing services for the CHOICE and SCO suppliers, Columbia's allocation process assigns a "slice of the pie" to all CHOICE and SCO suppliers on a "level playing field" basis. More succinctly, Columbia assigns FTS and storage capacity[6] on an equal percent of design peak day demand basis across all 12 PSPs. Additionally, Columbia assigns a "slice of the pie"

[5] Report at ES-5.

[6] Storage refers to both storage capacity and the related transportation capacity to Columbia city gates.

within each PSP. For example, the percentage of storage and FTS assigned to suppliers in the Toledo PSP is identical to that assigned suppliers in the Columbus PSP however, suppliers in the Toledo PSP are assigned a combination of Panhandle and TCO storage and FTS capacity while suppliers in Columbus are assigned only TCO storage and FTS. This process provides consistency across Columbia's wide-spread service territory and recognizes the operational requirements of each PSP to assure service reliability to CHOICE and SCO customers.

Q: Is this process designed to maximize assignment to CHOICE and SCO suppliers?

A: Yes. Consistent with the level playing field approach Columbia maximizes assignment to suppliers.

Q: Is there any capacity Columbia is not able to assign to CHOICE and SCO suppliers under this process?

A: Yes. Consistent with the Commission's directions to Columbia, North Coast and Staff in Case No. 08-1344-GA-EXM, Columbia will retain all remaining North Coast capacity and treat it as operationally required effective April 1, 2013. Additionally, in two PSPs the amount of TCO FTS capacity that requires the upstream delivery by Tennessee Gas Pipeline Company, L.L.C. ("TGP") exceeds that available for assignment in all PSPs to achieve a level playing field. Thus, Columbia retains the TCO/TGP capacity that exceeds the amount it is able to assign on a level playing field basis. Columbia incorporates both the North Coast and TCO/TGP capacities as part of the peaking service it provides all CHOICE and SCO suppliers equally.

Q: Is this capacity excess capacity?

A: No. While Columbia is not able to directly assign the operationally retained capacity to CHOICE and SCO suppliers, Columbia utilizes that capacity to the benefit of all CHOICE and SCO suppliers equally by incorporating the capacity into the peaking service Columbia provides all CHOICE and SCO suppliers and to supplement supplier provided supplies as needed to maintain system reliability.

Q: Can you please provide an example of how Columbia provides such system reliability maintenance?

A: Yes. TCO requires that deliveries be made from TGP at Dungannon in order for TCO to be able to meet its firm delivery obligations to Columbia in portions of Columbia's service territory in northeast Ohio. The delivery obligation from TGP is temperature sensitive and Columbia provides CHOICE and SCO suppliers with customers in this area a Supply Curve that defines the minimum delivery requirement of each supplier as temperatures decline during the winter season. Once the supply requirement into TCO from TGP exceeds the aggregate requirement of the Supply Curves provided to the CHOICE and SCO suppliers, Columbia provides additional supplies via the retained capacity in order to assure system reliability in this area of its service territory.

Q: Are there any other components of Columbia's capacity portfolio that Columbia is not able to assign CHOICE and SCO suppliers?

A: Yes. Columbia is not able to assign, either through contractual terms or practical means, the local gas supplies Columbia purchases from Gatherco, Producer's, and various small producers and city-gate purchases it makes for the Brewster market.

Q: Is Columbia proposing any changes to the allocation process in the case?

A: While the mechanics of the allocation process is identical to that approved by the Commission in Case No. 08-1344-GA-EXM actual assignment will change slightly due to changes in Columbia's capacity portfolio.

Q: What are the advantages of this assignment mechanism?

A: The advantages are numerous and include, among others:

- Maintains service reliability for all Columbia customers;
- Provides a consistent and level playing field between CHOICE and SCO suppliers;
- Minimizes operational complexities;
- Creates stability and certainty for all market participants;
- Lowers barriers to entry to potential new suppliers; and
- Minimizes potential supplier stranded costs from capacity that Suppliers would need to acquire and hold not knowing what their demand requirements may be month to month.

BALANCING SERVICE

Q: Please describe the balancing service Columbia provides CHOICE and SCO suppliers.

A: As system operator Columbia is required to balance the amount of gas delivered by all suppliers with the actual consumption of all customers across all its markets. CHOICE and SCO suppliers are required to deliver gas supplies for their customers based on the Demand Curves[7] provided by Columbia. While these Demand Curves represent expected customer consumption at a particular temperature they are based on a regression analysis of monthly demand vs. temperature. Since many factors can and do influence customer demand Columbia must retain no-notice service to manage the differences between supplies delivered by the suppliers and actual customer demand. To do this Columbia retains TCO and Panhandle storage capacity.

Q: Are other balancing services available to balance differences in demand and supply at Columbia's city gates?

A: No.

Q: Does Columbia provide any other services to CHOICE and SCO suppliers from this retained capacity?

A: Yes. Columbia provides a peaking service with this capacity and those other assets Columbia retains to maintain system reliability including the operationally retained capacity, the supply obligation into the Brewster market and the local gas resources.

Q: How does this peaking service work?

A: Columbia determines annually the amount of capacity and other resources it will retain at the same time it determines the amount of capacity to be assigned CHOICE and SCO suppliers under its capacity assignment mechanism. Columbia then determines the percentage of design firm day demand represented by these retained assets and develops the supplier Demand Curves wherein on a percentage basis the suppliers' obligation to deliver supplies to Columbia flattens out when the delivery obligation is equal to 100% of their customers' design day demand less the calculated peaking service percentage. When temperatures fall below that point on the Demand Curve where it flattens out, Columbia supplements the CHOICE and SCO supplier deliveries through the peaking service to meet customer demand.

[7] The Demand Curves provided by Columbia show increasing demand during the months of October through April and a levelized daily demand for each of the months of May through September.

Q: Does Columbia provide any other services with this retained capacity?

A: Yes. As I noted earlier, Columbia provides an interruptible banking and balancing service to its TS customers. Columbia provides this interruptible service utilizing that portion of the balancing capabilities derived from the retained no-notice storage service that is not needed to meet the daily balancing requirements of CHOICE and SCO customers. When Columbia anticipates that it will utilize all the capabilities of the retained no-notice storage service to satisfy CHOICE and SCO customer supply imbalances, it may issue an order restricting the availability of this service to TS customer's and their suppliers. Such restrictions are based on and implemented pursuant to a specific process agreed to by Columbia and the Columbia Customer Coalition pursuant to the terms of a Joint Stipulation and Recommendation approved by the Commission in Case No. 01-2607-GA-CSS on April 1, 2003. This process has continued and remains unchanged.

Q: In the Joint Motion filed in this case Columbia has proposed changing the rate for the balancing service. Please describe why Columbia is proposing this change.

A: Columbia is proposing this change to more accurately reflect the costs of the storage capacity Columbia retains to provide this service.

Q: In the Joint Motion filed in this case Columbia is proposing to change how the balancing fee is charged. Please describe why Columbia is proposing this change.

A. The balancing fee is presently being charged the CHOICE and SCO suppliers. The Stipulation proposes to instead charge the balancing fee directly to customers. This change is being proposed to provide consistency with the method utilized by DEOG as part of its auction process and to create greater transparency for customers as it relates to the actual cost of providing gas commodity service by their supplier.

Q: Was Columbia influenced by other parties in arriving at its decision to propose moving the balancing fee from being charged suppliers to billing customers directly?

A: Yes. During the course of Stakeholder discussions that ultimately led to the drafting of the proposed Stipulation, both the Staff and OCC questioned Columbia regarding the difference between the latest Retail Price Adjustment levels of DEOG and Columbia. In response to that challenge Columbia identified two major, and several minor, factors that influence that difference. The two major factors that comprise over two-thirds of the difference are the on-system storage of DEOG and the fact that DEOG charges its balancing fee to customers while Columbia presently charges suppliers. This inquiry by Staff and OCC, as well as Columbia's desire to create a more transparent commodity cost service, led to the proposed change contained in the Stipulation.

Q: Is there any possibility that customers will be charged twice for the same balancing fee—once, as part of their current contracts that include the balancing service, and then a second time as a direct charge from Columbia?

A: As the balancing fee applies to SCO service, Columbia is proposing to implement this change effective April 1, 2013 after the end of the current SCO period. Thus, SCO customers should not be charged twice for this service given the competitive bidding process utilized to determine the SCO suppliers. The SCO auction that will be implemented concurrent with this change will specifically have the balancing fee removed from the SCO suppliers' responsibility. Furthermore, the SCO auction provides a strong competitive alternative to CHOICE and Governmental Aggregator offers. Making the proposed change will further promote that competition by providing a strong signal to CHOICE and Governmental Aggregation suppliers to reduce their prices to compete with the SCO auction or risk losing their customers to the SCO program; a situation OCC and OPAE should favor based on comments in their Memorandum Contra.

SHALE GAS ISSUES

Q: Please describe Columbia's involvement associated with the development of shale gas resources in the Appalachian Basin.

A: For the last several years Columbia has met with and maintains contact with a number of producers active in developing shale gas supplies first, from the Marcellus Shale in Pennsylvania and West Virginia and more recently from the Utica Shale in Ohio and Pennsylvania. Additionally, Columbia has met with and maintains contact with several mid-stream operators as well as a number of interstate pipeline organizations developing infrastructure to handle this growing resource. Furthermore, Columbia stays abreast of infrastructure developments, industry activities and reviews announced projects for possible utilization by Columbia.

Q: How is the development of shale gas resources in the Appalachian Basin different than the traditional development Columbia deals with?

A: The differences are numerous and significant. For example, traditional Appalachian production that Columbia has experience with typically is low volume, low pressure whereas gas production from shale[8] is high volume, high pressure. Traditional Appalachian production typically occurred from single wells drilled on individual well pads whereas modern shale practices increasingly utilize a single well pad to drill multiple wells. Gathering systems for traditional Appalachian production often utilize low pressure lines whereas new gathering systems being developed for shale production are often high pressure systems, some approaching 1,000 p.s.i.g. operating pressures.

Q: What impediments does Columbia face in attempting to deliver shale gas supplies directly to its distribution system?

A: Columbia faces numerous obstacles, including but not limited to:

a. Gas quality: Gas resources currently being targeted by producers in the Utica Shale in eastern Ohio and the Marcellus Shale in southwest Pennsylvania have a high Btu level and high natural gas liquids[9] content.

b. Wellhead volumes: Columbia's markets that are closest in proximity to present drilling activity, as well as future activity trends communicated by the producers, tend to be very small, isolated and temperature-sensitive markets. These markets are generally incapable of absorbing the output of a single shale well, let alone multiple wells from a single well pad.

c. High pressures: Traditional Appalachian production is typically introduced into Columbia medium pressure distribution systems without posing unacceptable operating risks. Connecting a shale well with its much higher producing pressures into such a system poses unacceptable safety risks.

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[8] Discussions of shale gas production relate to gas produced from shale formations utilizing the modern practices of horizontal drilling and multiple hydraulic frac treatments. Traditional Appalachian production has included small volumes of production from shale formations utilizing more traditional vertical wells with smaller hydraulic frac treatments, if used at all.

[9] Natural gas liquids refer to hydrocarbon elements in a raw gas stream that are either recoverable as liquids through processing equipment located on the well site, i.e. filters or separators, or as liquids in a natural gas processing plant, typically elements such as propane, butanes, etc.

d. Producer Economics: Producers seek to maximize their economic return. This factor drives a desire to achieve 100% sale of the wells maximum efficient production level and recovery of valuable natural gas liquids for sale in liquid form. Neither of these objectives are obtainable by direct delivery to Columbia.

e. Safety: Above all else, Columbia must assure that its distribution systems are safe. Delivering natural gas supplies that create inherent risks to these systems must be avoided. High Btu shale supplies that contain large volumes of liquefiable hydrocarbons such as propane, butanes, etc. create such risks.

Q: Please describe in general the gas qualities of Appalachian Basin shale gas.

A: While several shale intervals are of interest to producers in the Appalachian Basin, the two of greatest present interest are the Marcellus and Utica Shales. Both of these shale formations have regions that are generically described as "dry gas" and "wet gas" areas. Additionally, the Utica Shale is believed to have a region that is primarily oil-prone. Oil-production from such areas is typically accompanied with "wet" gas. Dry gas is generally defined as gas that with minimal processing, typically involving only the removal of excess water vapor, can be introduced into interstate pipelines or local distribution systems. This gas is often referred to as "pipeline quality". Wet gas is generally defined as gas with higher btu levels and with higher levels of natural gas liquids. This gas must be processed through a natural gas processing facility to remove higher chain hydrocarbons such as propane, butanes, etc. before they can be safely introduced into an interstate pipeline or local distribution system.

Q: Why must higher chain hydrocarbons such as propane, butanes, etc. be removed from the raw gas stream?

A: Higher chain hydrocarbons are removed from raw gas streams for two primary reasons. First, for operational and safety reasons these higher chain hydrocarbon constituents are removed in natural gas processing plants to prevent them from dropping out of the gas phase as liquids which can create operational and safety issues in pipeline and distribution systems. Second, higher chain hydrocarbons are removed for economic reasons. Generally, the value of constituents such as propane, butanes, etc. is greater in the liquid phase then in the gaseous phase. Removing these constituents and selling them as liquids enhances the producer's economics.

Q: Is it common practice for a natural gas distribution system to be directly connected to a natural gas processing facility?

A: In Columbia's experience it is not common practice for a natural gas distribution system to be directly connected to a natural gas processing facility. However, in locations where an LDC may have sufficiently large nearby markets or the ability to move gas through large volume, high pressure LDC facilities to such markets and/or on-system storage, direct connections may be manageable.

Q: In a situation where an LDC could connect directly to a natural gas processing facility is it advisable for that facility to be relied upon as a sole source of supply?

A: No. As with any processing facility an upset to its process is possible at any time and such an upset could result in the loss of supply from that facility placing service to customers at risk.

Q: Earlier you noted that TCO had recently closed an open season on its Westside Expansion project, is Columbia aware of any other projects that would move gas west from the Marcellus/Utica region?

A: Yes, Columbia is aware of at least four other potential projects that have been offered to industry participants. These four projects are Texas Eastern's OPEN and TEAM 2014 Projects, TCO's Utica "Quick Link" Project and a joint venture project between Spectra Energy Corp, DTE Energy and Enbridge, Inc. called the NEXUS Gas Transmission Project. In addition, Rockies Express has discussed the possibility of reversing portions of its system to move gas east to west, but has not yet offered this as an option.

Q: Please describe briefly each of these projects.

A: Texas Eastern's OPEN Project was initially announced as a potential project including AEP and Chesapeake Natural Gas to move up to 800 MMcf/day of gas from locations in eastern Ohio to Texas Eastern's main west to east system near Clarington, Ohio. Texas Eastern's TEAM 2014 Project is designed to move up to 600 MMcf/day combined both eastward and westward on Texas Eastern' system from receipt points in southwest Pennsylvania. The project is in the pre-certification phase at FERC and has a present planned in service date of November 1, 2014. TCO's Utica "Quick Link" Project is designed to move Utica supplies from the tail gate of planned processing plants in central Harrison County, Ohio to new interconnections with DTI, REX, TCO and Texas Eastern. The NEXUS Project is a proposed pipeline originating in northeastern Ohio that will traverse northern Ohio and move into Michigan where it will interconnect with the Vector pipeline to move gas into Michigan and Ontario, Canada markets.

Q: Has Columbia reviewed these pipelines for possible service?

A: Yes, Columbia has met with the sponsors of each of these projects with an eye towards evaluating whether they might be future alternatives to its existing portfolio.

Texas Eastern's OPEN Project: This project was designed to move upwards of 800 MMcf/day of processed Utica gas supplies to Texas Eastern's mainline facilities. The 100% load factor demand cost was estimated to be approximately $0.40 per Dth for delivery into Texas Eastern's mainline. Because Columbia would require both OPEN and Texas Eastern mainline capacity to replace Columbia Gulf's approximate $0.14 per Dth 100% load factor rate this project is not considered a viable replacement to Columbia Gulf. Additionally, this pipeline would have very limited city gate access to Columbia's markets and is more expensive than present alternatives. Texas Eastern is presently negotiating with potential shippers. The present in service date is estimated to be November 1, 2015.

Texas Eastern's TEAM 2014 Project: This project is designed to move up to a total of 600 MMcf/day to markets both to the east and to the west of the primary receipt points in southwest Pennsylvania. This project is designed to primarily move Marcellus Shale gas production. The 100% load factor demand rate for this project is estimated to be $0.35 per Dth. Given the higher cost and reduced flexibility inherent in this project relative to Columbia Gulf this project is not considered a viable replacement to Columbia Gulf. Additionally, this pipeline would have very limited city gate access to Columbia's markets and is more expensive than present alternatives. The planned in service date of this project is November 1, 2014.

TCO's Utica "Quick Link" Project: This project was designed to move up to 500 MMcf/day initially with expansion capability from natural gas processing plants in northeastern Ohio to new interconnections with DTI, REX, Texas Eastern and TCO's existing system. This pipeline is similar in design to a "header" system enabling gas to be moved to multiple pipelines. TCO held a non-binding open season, but has been unable to obtain sufficient firm support to move forward on the project at this time. The original announced in service date of November 1, 2015 has been delayed by at least one year. The 100% load factor demand rate for this project is estimated to be approximately $0.30 per Dth depending on which pipeline interconnections were sought by potential shippers. Similar to Texas Eastern's OPEN Project additional downstream capacity on DTI, REX and Texas Eastern would be required to replace Columbia Gulf supplies utilizing this project. Thus, these options are not considered to be viable replacements to Columbia Gulf. Deliveries into TCO from the Utica "Quick Link" project were limited by the receipt capabilities of the TCO pipelines this project could interconnect with thus requiring additional investment and construction on TCO for this project to replace Columbia Gulf. Given these uncertainties and projected costs a Utica "Quick Link" connection into TCO is not considered a viable replace to Columbia Gulf or TCO.

NEXUS Gas Transmission Project: This project as presently configured is designed to move up to 1 Bcf/day of Utica sourced supplies from the tail gates of proposed processing facilities in northeastern Ohio to targeted markets in the upper Midwest and eastern Canada. Columbia has been informed by the NEXUS sponsors that the 100% load factor demand rate for this project for delivery to Michigan and Ontario markets is estimated to be in the range of $0.75 – $0.85 Dth. The NEXUS sponsors indicated that they were interested in possibly developing a rate structure that would provide a slightly lower rate for Ohio deliveries, but that they were not prepared to provide such a rate until they had been able to more fully assess the market demand for this service in their targeted markets. Additionally, NEXUS is very early in the routing stage of this project and was not able to provide Columbia with even a rough estimate of where the pipeline route may end up being located. Given the northern Ohio location of this proposed project and its costs (even at a 50% reduction to its target markets) this project is not seen as a viable replacement to Columbia Gulf or TCO.

Q: Given that only small volumes of Shale gas can presently be delivered to Columbia's distribution system, have Columbia's customers been able to take advantage of the reduction in prices driven by the increase in Appalachian Basin shale gas?

A: Yes they have. While Columbia customers have not been able to directly consume meaningful volumes of Appalachian Basin produced shale gas they have directly benefited through reduced prices in the market place driven by in the increase in natural gas production on both regional and national levels. A decrease that is primarily attributable to growing shale gas production nationwide. Under the SCO program the price SCO customers pay is the sum of the NYMEX closing price plus the auction derived Retail Price Adjustment. Since January 2006, the point in time often referred to when assessing the impact of increases in shale gas production, natural gas production in the lower 48 United States, as reported by the Energy Information Administration ("EIA"), has increased by over 32%. During that same period the average annual NYMEX monthly closing price has declined from $6.226 per Dth in 2006 to an average for the first eleven months of 2012 of $3.945 per Dth. Without question Columbia's customers have benefited from the regional and national growth in shale gas production. Attachment B is a graph of U.S. dry gas production by month as reported by EIA and the corresponding NYMEX monthly closing prices.

Q. Does the introduction of shale gas create uncertainty about how the interstate capacity is best used?

A: No, if anything it may create additional flexibility from the utilization of Columbia's existing portfolio. It will take several years to fully assess the full impacts of shale gas on Ohio markets, and until all market participants can assess these impacts it makes sense not to make long-term interstate pipeline capacity decisions that could adversely impact the reliability to Columbia's customers and Columbia's ability to make best use of all pipeline capacity available to it. Columbia needs to maintain flexibility without sacrificing reliability. This means that it is not wise to enter into longer term arrangements and Columbia's contracting approach does not create uncertainty.

Q: Do you have any comments regarding the flexibility provided by renewing the upstream interstate pipeline contracts as set forth in the Stipulation?

A: Yes I do. First, it is important to identify upstream interstate pipeline contracts into two categories. For purposes of this answer upstream contracts can be categorized as: (a) those with pipelines that deliver gas directly to Columbia's city gates, and, (b) those with pipelines that deliver gas to those pipelines in category (a). For Columbia the interstate pipeline capacity contracts in its capacity portfolio that fall into category (a) are provided by Panhandle and TCO. Those pipelines that fall into category (b) are Columbia Gulf, TGP and Trunkline. As I noted earlier in this testimony, gas supplies delivered by Columbia Gulf are critical to Columbia's ability to provide reliable service to its firm customers. TGP deliveries provide a similar benefit, but to a much smaller population of customers. Yet another benefit provided by this Columbia Gulf capacity is its ability to provide additional flexibility that would not be available if it were not a part of Columbia's capacity portfolio. This flexibility is derived from the opportunity to access multiple sources of supply/supply basins available to the Columbia Gulf system. Some parties may argue that shale gas that is not deliverable to Ohio customers is somehow more flexible. Furthermore, if you assume that Columbia did not have the upstream Columbia Gulf capacity and that Appalachian Basin shale supplies were physically available to meet the reliability needs of Columbia's customer's, flexibility would still be reduced because the Appalachian Basin shale supplies have a more limited range of availability than supplies available to Columbia Gulf.

Q. The Stipulation refers to the renewal of some interstate pipeline contracts for a five year period. Do you consider this five-year period to be long-term?

A: No. Five years is not considered long term with respect to contracting for interstate pipeline capacity. The means of moving Appalachian Basin shale gas resources to locations on the interstate grid that can successfully be utilized by Columbia to ensure reliable service to its firm, residential and small commercial customers will require new pipeline capacity which must be constructed; and that the developers of that new capacity require contracting parties to enter into 10-year, 15-year or even 20-year contracts to make the investment necessary to develop such capacity.

Q: In a Memorandum Contra filed by OCC and OPAE in this proceeding, they make the following statement, "Five years ago gas prices were approximately $7.25 per Mcf according to the New York Mercantile Exchange ("NYMEX") compared to today's price of approximately $3.25 per Mcf. Much of that price decline is attributable to a combination of decreased industrial demand due to the economic downturn and the introduction of Appalachian shale gas into the marketplace." Do you have any comments regarding this statement?

A: Yes, I do. First, over the last five years industrial consumption of natural gas has increased year over year, with the exception of 2009, and as of 2011 (which is the last full year of industrial consumption reported by Energy Information Administration ("EIA")) is at its highest level since 2004. Additionally, industrial consumption for the first 8 months of 2012 exceeds that of the same period in 2011. Furthermore, total U.S. consumption of natural gas has grown annually over the last five years with the exception of a slight 1.6% decline in 2009, and as of 2011 stood at its highest reported annual level ever. Similar to the consumption growth for industrial demand in 2012, total U.S. consumption for the first 8 months of 2012 exceeds that of 2011. Turning to OCC and OPAE's claims of the impact of Appalachian shale gas, as shown on Attachment B, the growth in lower 48 U.S. production started in 2006. Yet, according to the EIA, as late as 2008, total shale gas production combined from Ohio, Pennsylvania and West Virginia totaled 1 Bcf, less than 0.05% of the total U.S. shale gas reported by EIA for that year. Moving forward to 2009 and 2010, the last years that shale volumes have been reported by the EIA, the three-state total was 76 Bcf and 476 Bcf, respectively. By 2010 Appalachian shale volumes had grown to 8.9 % of U.S. total shale production. In my opinion, this contribution from Appalachian shale cannot properly be characterized as being responsible for "much of that price decline". While NYMEX prices during 2012 have continued to decline, much of this decline is attributable to the record warmth experienced during the winter of 2011-12. While Appalachian shale production has grown rapidly in 2012 characterization of that growth as being responsible for "much of that price decline" over the last five years is wrong and a gross over simplification of the complex issues involved in establishing natural gas price as represented by NYMEX. To somehow use these misrepresentations against contracting for capacity needed to ensure reliable service would not be prudent.

Q: Does Columbia's renewal of upstream interstate capacity have the effect of closing the door on any immediate investment that would provide for shale gas opportunities in Ohio during the next five years?

A: No. Obviously, producers are not going to immediately stop all drilling activities because Columbia has renewed its contracts. Interstate pipeline companies with announced infrastructure projects are not going to immediately stop pursuing producers to support development of those projects because Columbia has renewed its contracts. Companies developing natural gas processing facilities are not going to immediately stop building those plant, some in the middle of constructing those facilities, just because Columbia has renewed it interstate pipeline contracts. Columbia's renewal of its interstate pipeline contracts will have no perceptible impact on the development of shale resources in Ohio. As I have previously explained, the benefits of shale production have already accrued to Ohioans and will continue to accrue with assured reliability and there will be no loss of flexibility attributable to Columbia renewing its upstream interstate pipeline contracts.

Q: Do the interstate pipeline capacity contract provisions of the Stipulation build in flexibility to address changes to the natural gas market in Ohio due to the introduction of shale gas?

A: Yes. As I have previously demonstrated, the Stipulation preserves flexibility and assures continued reliability of service. The Stipulation recognizes that the shale industry in Ohio is in its infancy, a fact supported by delays in the development of two of the four announced interstate pipeline projects with the potential ability to move shale gas to locations that can reliably be used by Columbia to assure service to its firm, residential and small commercial customers. The Stipulation recognizes that constructing new interstate pipeline capacity is a costly and time consuming process, costs that can yield rates that are multiples of Columbia's legacy contracts and timelines that can be delayed by various factors.

OFF-SYSTEM SALES AND CAPACITY RELEASE

Q: Please describe what comprise off-system sales and capacity release activities.

A: Columbia's Off System Sales ("OSS") activities take place only after it has assured service reliability to its firm customers. Once this assurance has been accomplished, Columbia's traders identify opportunities using the available capacity and gas supply resources and make contacts with its industry trading partners to determine if interest exists to execute a transaction. Similarly, each month Columbia analyzes what transportation capacity may be needed to assure service reliability to its firm customers. Once the level of capacity has been determined that is needed to assure service reliability, Columbia solicits bids through electronic communication means with potential buyers of capacity available for temporary release. Should acceptable bids be forwarded, Columbia releases the subject capacity through the capacity release process approved by FERC for each interstate pipeline.

Q: In their Memorandum Contra filed in this case, OCC and OPAE claim that customers will be giving up $60 million in off-system sales transactions revenues to Columbia, and will be required to pay for upstream interstate pipeline capacity that may not be needed but will instead be used to generate the of-system sales. Do you agree with this statement?

A: No. First, as I have previously demonstrated Columbia does not have excess or unneeded capacity and thus, customers are not paying for and Columbia cannot generate off-system sales from excess or unneeded capacity. The capacity Columbia retains under the CHOICE/SCO capacity assignment mechanism is only that capacity it must retain to manage system operations. All other capacity is assigned to CHOICE and SCO suppliers. Furthermore, customers are not giving up anything. In fact, they will continue to benefit from Columbia's off-systems sales and capacity release activities. Off-system sales are generated through the actions and efforts of Columbia. The sharing mechanism in the Joint Motion, which is substantially identical to that contained in the 08-1344-GA-EXM case stipulation, incents Columbia and recognizes its efforts, and rewards customers along with a share of Columbia's success.

Q: Are off-system sales revenues generated by Columbia achieved by using capacity that customers pay for?

A: No. Columbia contracts for this capacity and through the assignment of capacity to suppliers assign certain cost responsibility to suppliers. Columbia and suppliers recover these costs through the provision of services to customers. The recovery of costs through the provision of services does not create a unilateral entitlement to other revenues generated by these assets. Columbia and its Stakeholders have a very long history of developing settlements as to how such other revenues are shared between Columbia and its customers.

Q: Is the mechanism for sharing off-system sales and marketed capacity release revenue different under the Stipulation filed in this case?

A: The sharing mechanism proposed under the Stipulation in this case is identical to that approved by the Commission in Case No. 08-1344-GA-GCR with one exception. That exception is that the potential revenue that Columbia may retain is reduced from an annual average of $14 million ($42 million over three years) to $12 million ($60 million over five years).

Q: Under the Stipulation, do customers receive any benefits from the off-system sales sharing mechanism?

A: Yes. Nothing in the Stipulation filed in this case changes the quid-pro-quo that existed when the mechanism was originally established. All of the customer benefits contained in the Stipulation in the 08-1344-GA-EXM case remain in the current proposed Stipulation.

Q: Does the introduction of shale gas increase the likelihood that Columbia's capacity contracts might include excess capacity?

A: No. Columbia does not have excess capacity. There are only two ways that shale gas can provide an alternative to Columbia's portfolio: First, the shale gas could be directly connected to Columbia's distribution system. But, as I have observed, shale gas being developed in Ohio cannot be directly connected to Columbia's distribution system for reliability, economic, utilization and safety concerns. Once processed this gas must be transported to Columbia's wide-spread service territory, available to be used in a temperature-sensitive manner and be made available for injection into storage, something that cannot be done without Columbia's existing portfolio of city gate capacity. Second, the shale gas could replace an upstream capacity resource, i.e. Columbia Gulf or TGP capacity. But, here again as I noted above, currently announced projects are not cost-effective, reliable alternatives to Columbia Gulf. Nor do they provide the flexibility provided by Columbia Gulf. Certainly the possibility exists that future projects may be proposed that can overcome some of these present hurdles. However, from a timing stand point they would not be available until near the end of the five-year period proposed by the Stipulation. Furthermore, any alternative to Columbia Gulf must have the flexibility to facilitate storage injection capacity thus preserving the critical operational accessibility to storage supplies.

Q: In their Memorandum Contra filed in this docket, OCC and OPAE have expressed a concern that any excess capacity is assigned to marketers such that it matches the Choice/SCO suppliers' customer groups. Because the capacity is allocated on a pro-rata basis based on the suppliers served load, no supplier is put at a competitive disadvantage by holding excess capacity. The OCC and OPAE then opine that the suppliers merely pass the costs of any excess capacity on to their customers." Do you agree with the OCC and OPAE?

A: No. As I have noted, the OCC/OPAE position that Columbia may have excess capacity is incorrect. However, in any event, OCC and OPAE contradict themselves. On the one hand OCC and OPAE appear to believe that Columbia may have excess capacity to generate off-system sales. On the other hand the OCC and OPAE appear to claim that Columbia allocates excess capacity pro-rata to serve suppliers served load. Neither is correct. Columbia does not hold excess capacity. And thus suppliers do not "merely pass the cost of any excess capacity on to their customers" as no excess capacity exists. By Columbia assigning suppliers capacity that matches the Choice/SCO suppliers' customer groups need, suppliers, particularly SCO suppliers, are not placed in a position of having to acquire capacity that they don't know if they will need. This is driven by the fact that SCO suppliers do not know the level of their customers month to month, driven by natural changes in customer levels, but more importantly by what actions CHOICE suppliers may take that affect those levels. By Columbia assigning capacity this uncertainty is largely eliminated and costs to customers, particularly SCO customers are minimized.

STIPULATION TIMELINE

Q: Why are the Stipulating parties requesting that the Commission act upon the Stipulation by the end of December 2012?

A: While Columbia has already renewed many of its interstate pipeline contracts for the five-year period contemplated by the Stipulation, Columbia also must act on North Coast and Tennessee contracts that are a part of its capacity portfolio. Additionally, critical elements that are prerequisites to conducting the SCO auction to be effective April 1, 2013 must be resolved by the end of 2012. Columbia and potential SCO suppliers have a number of requirements that must be ruled upon by the Commission prior to holding the SCO auction. These requirements include, but are not limited to, items such as whether changes to the Balancing Fee are approved, changes to the capacity allocation formula, and application of the $.10 per Dth SCO supplier fee. Columbia must know this outcome in order to provide potential suppliers accurate educational materials to perform required credit checks, as well as enable the potential suppliers to make application to participate and develop their bidding strategy. If the Stipulation is not acted upon by the end of December 2012, there will be a great deal of uncertainty in the next SCO auction because some of the terms and conditions affecting the auction will be undetermined. Absent an order by year end, this uncertainty will lead to reduced transparency and clarity for the suppliers as they prepare for the next SCO auction. Such increased uncertainty and reduced clarity leads to the possibility of higher RPA prices due to the unknowns.

Q: Does this conclude your Prepared Direct Testimony?

A: Yes it does.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Prepared Direct Testimony of Michael D. Anderson was served upon all parties of record by electronic mail this 12th day of November, 2012.

/s/ Stephen B. Seiple
Stephen B. Seiple
Attorney for
COLUMBIA GAS OF OHIO, INC.

SERVICE LIST

Stephen Reilly
Assistant Attorney General
Public Utilities Section
180 East Broad Street, 6th Floor
Columbus, OH 43215-3793
stephen.reilly@puc.state.oh.us

M. Howard Petricoff
Vorys, Sater, Seymour and Pease LLP
52 East Gay Street
P.O. Box 1008
Columbus, OH 43216-1008
mhpetricoff@vorys.com

Barth E. Royer
Bell & Royer Co., LPA
33 South Grant Avenue
Columbus, OH 43215-3927
barthroyer@aol.com

Larry S. Sauer
Joseph P. Serio
Office of the Ohio Consumers' Counsel
10 West Broad St., Suite 1800
Columbus, OH 43215-3485
sauer@occ.state.oh.us
serio@occ.state.oh.us

Dane Stinson
Bailey Cavalieri LLC
10 West Broad St., Suite 2100
Columbus, OH 43215
dane.stinson@baileycavalieri.com

Dave Rinebolt
Colleen L. Mooney
Ohio Partners for Affordable Energy
231 West Lima Street
P.O. Box 1793
Findlay, OH 45839-1793
drinebolt@ohiopartners.org
cmooney@ohiopartners.org

A. Brian McIntosh
McIntosh & McIntosh
1136 Saint Gregory Street, Suite 100
Cincinnati, OH 45202
brian@mcintoshlaw.com

Glenn S. Krassen
Matthew W. Warnock
Bricker & Eckler LLP
1001 Lakeside Avenue East, Suite 1350
Cleveland, Ohio 44114
gkrassen@bricker.com
mwarnock@bricker.com

John L. Einstein, IV
790 Windmiller Drive
Pickerington, OH 43147
jeinstein@volunteerenergy.com

Joseph M. Clark
6641 North High Street, Suite 200
Worthington, OH 43085
Joseph.clark@directenergy.com

Matthew White
6100 Emerald Parkway
Dublin, Ohio 43016
mswhite@igsenergy.com

M. Anthony Long
Honda of America Mfg., Inc.
24000 Honda Parkway
Marysville, Ohio 43040
Tony_long@ham.honda.com

ATTACHMENT A

Columbia Gas of Ohio
Design Peak Day Capacity Portfolio

City Gate

Pipeline	Rate Schedule	Contract No.	Contract Capacity
TCO	Storage Transportation		
	SST	03044	1,445,102
	FTS	80152	238,186
		82544	38,974
		82545	29,231
		85154	45,538
			351,929
North Coast	FT	30014-A	35,000
		30013-A	7,593
			42,593
PEPL	Storage Transportation		
	EFT	018606	26,338
	Long Haul West End		
	EFT	018605	15,000
	Short Haul - Winter Only		
	EFT	018604	28,662
			70,000
	Total Pipeline		1,909,624

Upstream

Pipeline	Rate Schedule	Contract No.	Contract Capacity
Firm Transportation			
Columbia Gulf	FTS-1	80061	273,629
Crossroads	FT-1	TBD	7,689
Tennessee	FT-A	46986	40,000
	FT-A	63440	30,000
Trunkline			
Storage			
TCO	FSS-MDSQ	3045	1,445,102
	FSS-SCQ		80,441,913
PEPL	FS-MDQ	18601	26,667
	FS-SCQ		2,000,000

LOCAL

Gatherco	22,840
Producers	6,000
Misc Small	800
Brewster	950
Total Local	30,590

TOTAL CITY GATE RESOURCES **1,940,214**

ATTACHMENT B

Attachment B
Prepared Direct Testimony
Michael D. Anderson