UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Portland Natural Gas Transmission System **Docket No. RP08-____**

Prepared Direct Testimony
of
James S. Taylor

Q.1 Please state your name and address.

A.1 My name is James S. Taylor. My business address is 1155 15th Street, N.W, Suite 400, Washington, D.C. 20005.

Q.2 By whom are you employed and in what capacity?

A.2 I am an independent consulting engineer associated with the firm of Brown, Williams, Moorhead & Quinn, Inc.

Q.3 On whose behalf are you presenting testimony in this proceeding?

A.3 I am presenting testimony on behalf of Portland Natural Gas Transmission System ("PNGTS").

Q.4 Are you sponsoring any exhibits in connection with your testimony?

A.4 Yes. I have prepared and am sponsoring Exhibits No. PNG-17 and PNG-18. I will discuss and explain these exhibits in the course of my testimony.

Q.5 Please briefly describe your educational background and professional experience.

A.5 I received a Bachelor of Science degree in Civil Engineering from Virginia Polytechnic Institute in 1970 and a Master of Science degree in Public Works Engineering from George Washington University in 1981. I have also completed four courses in depreciation sponsored by Depreciation Programs, Inc.; a course in basic petroleum engineering and a course in natural gas reservoir engineering, both sponsored by Oil and Gas Consultants International, Inc.; a course in natural gas underground storage sponsored by Continuing Engineering Education Corp.; and a course in construction cost estimating and bidding sponsored by George Mason University.

From September 2003 through the present, I have been associated with Brown, Williams, Moorhead & Quinn, Inc. From March 1979 through September 2003, I was employed by the Federal Energy Regulatory Commission ("FERC" or "Commission") initially as a civil engineer and later as a regulatory gas utility specialist. My responsibilities with the Commission included conducting depreciation studies and various types of salvage analyses (including final abandonment studies) of electric, gas pipeline, and oil pipeline companies. I also conducted various types of gas transmission and underground storage cost allocation studies. Prior to my employment with the Commission, I was employed from June 1970 through February 1979 by the District of Columbia Department of Transportation as a highway engineer in the Bureau of Design, Engineering, and Research. During that period, I was engaged in highway design which involved the preparation of plans, specifications, and construction cost estimates. Highway construction cost estimates that I prepared were used for contractor bid evaluation purposes.

I am a registered professional engineer in the Commonwealth of Virginia and a member of the American Society of Civil Engineers. I am also a member of the Society of Depreciation Professionals.

Q.6 Have you previously provided testimony in proceedings before the Federal Energy Regulatory Commission?

A.6 Yes, I provided testimony in the following natural gas and oil pipeline rate proceedings:

RP83-35-000, et al., Texas Eastern Transmission Corporation;
RP85-37-000, High Island Offshore System;
RP85-150-000, Natural Gas Pipeline Company of America;
IS85-9-000, Kuparuk Transportation Company;
RP87-62-000, Pacific Gas Transmission Company;
RP88-120-000, Chandeleur Pipe Line Company;
RP88-93-000, et al., Questar Pipeline Company;
RP89-58-000, Bear Creek Storage Company;
RP89-86-000, Chandeleur Pipe Line Company;
RP90-139-000, et al., Southern Natural Gas Company;
RP91-212-000, Stingray Pipeline Company;
RP92-134-000, Southern Natural Gas Company;
RP92-236-000, et al., Williston Basin Interstate Pipeline Company;
RP93-15-000, Southern Natural Gas Company;
RP93-61-000, U-T Offshore System;
RP93-4-000, Mississippi River Transmission Corporation;
RP93-36-000, Natural Gas Pipeline Company of America;
RP94-149-000, et al., Pacific Gas Transmission Company;
IS94-23-000, et al., Gaviota Terminal Company;
IS94-22-000, et al., Chevron Pipe Line Company;
RP94-43-000, ANR Pipeline Company;
IS94-32-000, Chevron Pipe Line Company;

RP95-112-000, Tennessee Gas Pipeline Company;
RP95-409-000, Northwest Pipeline Corporation;
IS95-35-000, Gaviota Terminal Company;
RP95-167-000, Sea Robin Pipeline Company;
RP95-408-000, Columbia Gas Transmission Corporation;
RP96-190-000, Colorado Interstate Gas Company;
RP96-290-000, Michigan Gas Storage Company.
RP97-373-000, Koch Gateway Pipeline Company;
RP98-203-000, Northern Natural Gas Company;
RP98-117-000, KN Interstate Gas Transmission Company;
RP99-166-000, Stingray Pipeline Company;
RP99-485-000, Kansas Pipeline Company;
RP00-107-000, Williston Basin Interstate Pipeline Company;
RP01-245-000, et al., Transcontinental Gas Pipe Line Corporation;
RP02-13-000, Portland Natural Gas Transmission System;
RP03-162-000, Trailblazer Pipeline Company;
RP03-221-000, High Island Offshore System, L.L.C.;
RP06-417-000, Dominion Cove Point LNG, L.P.
RP06-569-000, Transcontinental Gas Pipe Line Corporation;
RP07-34-000, Southwest Gas Storage Company; and
RP07-541-000, Southwest Gas Storage Company.

Q.7 What is the purpose of your testimony in this proceeding?

A.7 My testimony describes and explains the determination of my recommended final abandonment cost of PNGTS' transmission plant for use in this proceeding.

Q.8 What conclusions have you reached with respect to the final abandonment costs of PNGTS' transmission plant?

A.8 After developing and reviewing three alternative final abandonment estimates, referred to as Options I, II, and III, and described below**,** I recommend that my Option III estimate of

$37,004,031 be adopted in this proceeding. My three final abandonment estimate alternatives (in December 2007 dollars) for PNGTS' transmission plant are summarized below:

Option I:	$ 35,177,667
Option II:	$ 56,428,009
Option III:	$ 37,004,031

I provided my Option III final abandonment estimate of $37,004,031 for PNGTS' transmission plant to PNGTS witness Mr. Barry A. Sullivan for his use in this proceeding.

Q.9 Mr. Taylor, before you proceed any further, would you explain what is meant by the term "final abandonment"?

A.9 "Final abandonment" refers to the retirement of a property at the end of its service life and is equivalent to the term "final closure." There are costs associated with the retirement to ensure that the property is safely and legally removed from service and not a future risk to the public. The final abandonment cost is the difference between the revenues realized from the sale or disposal of the asset (referred to as the gross salvage) and the costs associated with the retirement (referred to as the cost of removal).

Q.10 Did you include an allowance in your estimates for potential future liability associated with pipelines abandoned in-place and filled with nitrogen?

A.10 No. If future liabilities related to pipelines abandoned in-place and filled with nitrogen should occur (Options I and III), there are no provisions in Options I and III to recover these additional costs.

Final Abandonment Estimate

Q.11 Please briefly describe PNGTS' transmission facilities.

A.11 PNGTS is a gas transmission system that began operations on March 10, 1999. Its transmission facilities are located in the States of New Hampshire, Vermont, Maine, and Massachusetts. PNGTS' transmission facilities include wholly-owned and jointly-owned facilities. PNGTS' wholly-owned facilities include approximately 144 miles of 24" mainline and 44 miles of associated laterals; 7 meter and regulation ("M&R") stations; 15 remote valve sites; and numerous miscellaneous facilities necessary for system operation. The wholly-owned, 24" mainline extends southeastward from the Canadian border near Pittsburg, New Hampshire to Westbrook, Maine where it intersects with a jointly-owned 30" mainline and associated facilities. From Westbrook Maine, the 30" jointly-owned mainline extends in a southwesterly direction to Dracut, Massachusetts.

The jointly-owned facilities mentioned above are owned by PNGTS and Maritimes & Northeast Pipeline, L.L.C. ("Maritimes"). PNGTS' jointly-owned facilities include approximately 102 miles of 30" mainline and 4 miles of associated laterals; 12 M&R stations; 16 remote valve sites; and numerous miscellaneous facilities necessary for system operation. PNGTS would have to work in conjunction with Maritimes to coordinate and carry-out the final abandonment of these jointly-owned facilities.

Q.12 Describe the scope-of-work upon which Options I, II, and III are based?

A.12 The scope-of-work for each option is described below.

Option I – Minimum pipe removal footage

Remove all surface facilities and restore the sites; grout pipelines located at highway crossings, railroad crossings, trenched river and large stream crossings, and small stream crossings and abandon in-place; fill pipelines located at horizontal directionally drilled (“HDD”) river and stream crossings with water and abandon in-place; fill pipelines not located at crossings or in 18 specified locations (14,261 feet of pipe), where the pipe must be removed based on ROW agreements, with nitrogen and abandon in-place; and remove and salvage pipelines in the 18 specified locations.

Option II – Maximum pipe removal footage

Remove all surface facilities and restore the sites; grout pipelines located at highway crossings, railroad crossings, trenched river and large stream crossings, and small stream crossings and abandon in-place; fill pipelines located at HDD river and stream crossings with water and abandon in-place; and remove and salvage all PNGTS pipelines not located at crossings.

Option III – Intermediate pipe removal footage

Remove all surface facilities and restore the sites; grout pipelines located at highway crossings, railroad crossings, trenched river and large stream crossings, and small stream crossings and abandon in-place; fill pipelines located at HDD river and stream crossings with water and abandon in-place; fill pipelines not located at crossings, in 18 specified locations (14,261 feet of pipe), or in Class 3 locations (i.e. developed areas) with nitrogen and abandon in-place; and remove and salvage pipelines in the 18 specified locations and in Class 3 locations.

Q.13 Mr. Taylor, why did you select Option III for use in this proceeding?

A.13 I chose Option III because it reasonably takes into consideration that a substantial amount of pipe would need to be removed and salvaged. Option III is an intermediate option, falling between Options I and II, with respect to the amount of pipeline estimated to require removal at the time of final abandonment. Option I, which includes provisions for abandoning all PNGTS pipe in-place (with the exception of 14,261 feet of pipe at 18 specific locations), is at the low end of the range of estimated final abandonment costs. Option II, which includes provisions for removing and salvaging all PNGTS pipe not located at crossings, is at the high end of the range. Option III, which includes provisions for removing 14,261 feet of pipe at 18 specific locations and pipe in United States Department of Transportation ("U.S. DOT") designated Class 3 locations, is at the lower end of the range of final abandonment costs and is the most realistic of the three options. Approximately, 17.7 miles (9%) of PNGTS wholly-owned pipe and 13.5 miles (13%) of PNGTS jointly-owned pipe is removed and salvaged in Option III. However, as discussed earlier in my testimony, neither Option I nor Option III takes into account the potential for any future liabilities which may arise from abandoning pipe in place that is filled with nitrogen.

Q.14 Please describe how your Option I, II, and III estimates are organized.

A.14 My Option I, II, and III estimates are summarized in Exhibit No. PNG-18, pages 1-3, 4-6, and 7-9, respectively. The estimate for each option includes a breakout for wholly-owned facilities, designated as subpart (a), and jointly-owned facilities, designated as subpart (b). Support for these estimates is included in Exhibit No. PNG-18, pages 10-78. The estimate for each option and option subpart contains three sections. The first section, Pipeline Retirement, is a breakout of costs by line item that would be experienced during the final abandonment. The second section, Salvage, acknowledges the estimated gross salvage value of PNGTS' transmission plant at the time of final abandonment. The third and final section, Contingency, reflects a 10 percent contingency that is calculated based on Section I of the estimate to allow for miscellaneous expenses that are expected to occur, but not specifically identified and included in line items in the estimate.

Q.15 What major government regulations did you review during the development of your estimates?

A.15 I reviewed U.S. DOT minimum safety regulations (49 CFR § 192.727), and pipeline class location guidelines (49 CFR § 192.5). U.S. DOT minimum safety regulations require pipelines abandoned in-place to be disconnected from all sources and supplies of gas; purged of gas; and the pipelines sealed at the ends. U.S. DOT pipeline class location guidelines categorize the extent of development in the vicinity of gas pipelines as Classes 1 through 4 with Class I being the least developed area and Class 4 being the most highly developed area.

I also reviewed U.S. Department of the Army regulations that give the U.S. Army Corps of Engineers ("U.S. Army COE") the authority to clear wrecks and other obstructions within the navigable waters of the United States (33 CFR Part 245) and issue permits for the discharge of dredged and fill material into the waters of the United States (33 CFR Part 323).

Q.16 What other information did you rely on during the development of your estimates?

A.16 For the particular type of information required during the development of my estimates, I relied on sources commonly utilized in the construction industry. In addition to these commonly used construction industry sources, I also relied on information and data supplied by PNGTS that included the following: (1) PNGTS maps, schematic drawings, and documentation describing and depicting the system; (2) the final abandonment estimate prepared in 2001 by Parsons Energy & Chemicals Group, Inc. ("Parsons") for use in Commission Docket No. RP02-13-000, Portland Natural Gas Transmission System; (3) various design drawings of PNGTS facilities; and (4) PNGTS pipeline abandonment guidelines.

Q.17 Did you develop a detailed set of parameters upon which your final abandonment estimates are based?

A.17 Yes. Exhibit No. PNGTS-17 contains a list of 17 parameters that define the tasks upon which my estimates are based.

Q.18 What tasks are included in your three final abandonment estimates?

A.18 Options I, II, and III include the following tasks:

1. Clean and purge pipelines;
2. Fill pipelines with nitrogen (not applicable to Option II);
3. Pipe removal;
4. Pipe handling and storage;
5. Grout railroad crossings;
6. Grout highway crossings;
7. Grout small stream crossings;
8. Fill HDD river and large stream crossings with water;
9. Grout trenched river and large stream crossings;

10. Remove remote valve sites;
11. Remove cathodic protection facilities;
12. Remove pipeline markers;
13. Remove M&R stations.

My estimated tasks are predicated on using the most economical method of retirement compatible with PNGTS right-of-way ("ROW") agreements, environmental considerations, U.S. DOT regulations pertaining to minimum safety requirements and class location guidelines, and U.S. Army COE regulations pertaining to navigable waters and dredge and fill permits.

Q.19 Please explain what steps PNGTS would take to clean and purge its pipelines.

A.19 First, PNGTS would pig its pipeline system using scraper pigs to remove any potential accumulation of hydrocarbons in the pipeline. I estimated that PNGTS would conduct two separate pig runs to insure that its pipelines are free of any hydrocarbon accumulations. Because PNGTS' natural gas stream is very clean and free of liquids, there is no allowance in my estimates for any more extensive pipeline cleaning. Second, after the last delivery to its shippers, PNGTS' personnel would isolate its pipelines from all receipt and delivery points. PNGTS would then "bleed-off" and salvage its line pack at selected delivery points until an abandonment pressure of approximately 200 psig is reached. Third, PNGTS' personnel would blow-down or flare the remaining line pack in its pipelines at valve sites. At this point, PNGTS' pipelines would be filled with natural gas at atmospheric pressure. Fourth and finally, using evacuation equipment, PNGTS' personnel would displace the remaining natural gas in its pipelines with air at atmospheric pressure.

Q.20 Why did you include a line item in Options I and III for filling pipelines abandoned in-place with nitrogen?

A.20 I included a line item for filling pipelines abandoned in-place with nitrogen as a safety precaution. By filling its abandoned pipelines with nitrogen, PNGTS would insure compliance with U.S. DOT minimum safety regulations and eliminate the possibility of any explosive mixture forming in its abandoned pipelines.

Q.21 How did you develop the cost to remove pipelines in Options I, II, and III?

A.21 As shown in Exhibit No. PNG-18, pages 14-19, I first developed the equipment and labor spread necessary to remove a 24" diameter pipeline. Then, I calculated the cost to remove the 24" pipeline on a per-foot basis. Finally, I used my estimated cost per-foot to remove a 24" pipeline to estimate the cost per-foot to remove pipelines larger and smaller than a 24" pipeline. To do this I employed the Six-Tenths sizing model. The equation for the Six-Tenths sizing model follows:

$$\text{cost}_1/\text{cost}_2 = (\text{size}_1/\text{size}_2)^{0.6}$$

The Six-Tenths sizing model is typically used in the chemical industry for making pro-rata estimates of the cost to construct chemical processing equipment that is similar in design but varies in size from chemical processing equipment whose size and cost are known. The chemical industry and gas transmission industry generally employ similar piping and equipment. The Six-Tenths sizing model is useful because it takes into consideration the economies of scale that occur during construction (or demolition) when the size of tanks, pipe, or equipment differ.

Q.22 Mr. Taylor, why did you include line items in each option for grouting pipelines at railroad and highway crossings?

A.22 Generally speaking, grout consisting of a mixture of Portland cement and water, is used to fill underground cavities. Grouting of pipelines at railroad and highway crossings is necessary to insure that subsidence of railroad track bed and highway surface does not occur should the retired pipeline corrode and lose its load-bearing capacity. Where pipeline exists within a casing at railroad or highway crossings, the pipeline would first be removed and the casing then grouted. Each of my options includes line items for grouting pipelines at all railroad and highway crossings.

Q.23 Similarly, why did you include line items in each option for grouting pipelines at trenched river and large stream crossings and at small stream crossings?

A.23 Should the U.S. Army COE believe that an abandoned PNGTS pipeline would pose a hazard to navigation on any water body, it would most likely mandate removal of the pipeline. Such removal would be an environmentally disruptive and expensive undertaking. Grouting pipelines at trenched river and large stream crossings and at small stream crossings would increase the mass of the pipe and minimize the possibility of pipe movement, and, thus reduce or eliminate the need to remove pipe at trenched locations. Grouting would also insure that any residual hydrocarbons on the pipe wall do not enter the water body.

Q.24 How did you estimate the number of small stream crossings that require grouting?

A.24 The 2001 Parsons estimate indicated that approximately 2,776 small stream and culvert crossings required special consideration during construction. To allow for the additional work to abandon pipelines at small streams (and culvert crossings); I conservatively estimated that grouting PNGTS pipeline at one stream crossing per mile would be necessary. This would involve grouting wholly-owned pipeline at 188 small stream crossings and jointly-owned pipeline at 106 small stream crossings and amount to grouting pipeline at approximately 10 percent of total small stream crossings.

Q.25 Does your inclusion of grouting costs at trenched river and large stream crossings and small stream crossings take into consideration situations where additional costs at these locations would be incurred?

A.25 Yes. At trenched river and large stream crossings and at small stream crossings, where scouring would most likely expose PNGTS pipelines, PNGTS may reasonably decide to remove these pipelines to avoid future liability. Inclusion in my options of the cost to grout pipelines at trenched river and large stream crossings and at small stream crossings takes into consideration a variety of potential additional costs at these locations that PNGTS will face when its pipelines reach the end of their service lives.

Q.26 Please explain why you included a separate line item in each option for retiring HDD crossings?

A.26 PNGTS has 12 wholly-owned HDD crossings averaging 1,100 feet in length, and 7 jointly-owned HDD crossings averaging 1,600 feet in length. Due to the depth of these HDD crossings below the river or stream bed, it is unlikely that scour would ever expose the pipelines at these locations. Accordingly, I conservatively estimated that it would not be necessary to grout the pipelines at these locations. Instead, costs were included in this line item for filling the pipelines with water instead of the more expensive operation of grouting the pipe.

Q.27 What is the basis for your M&R station removal estimates?

A.27 My M&R station removal estimates reflect the tasks, time, material, and equipment and labor spread necessary to remove small and medium M&R stations. First, miscellaneous material and fencing would be removed to make the site ready for demolition work. Second, valves, blow-downs, buildings, and yard piping would be removed. This work involves excavation, cutting, lifting, and hauling. Salvageable material would be disconnected, lifted, and transported to a temporary location for disposition by a salvage contractor. Third, gravel and miscellaneous debris would be removed. This work involves excavation, loading, and hauling. Finally, the site would be restored by backfilling, grading, placing top soil, seeding, and fertilizing.

Q.28 Do the line items in each of your options include site restoration costs?

A.28 Yes. Estimated site restoration costs to restore disturbed areas to pre-existing conditions are included in pipeline contractor costs.

Q.29 What labor rates did you use in each option?

A.29 I used September 2007 union labor rates for Syracuse, New York. I then added a 25 percent factor for labor overhead, which consists of taxes and insurance that contractors must pay. Social security taxes, state and federal unemployment taxes, and workers compensation insurance are included in this cost category. I also included an adjustment factor of 1.17 for overtime pay in each labor rate. Exhibit No. PNG-18, page 66 includes a summary of the labor rates that I used in each option.

Q.30 Did you include a per diem allowance in each option?

A.30 Yes. I included a per diem allowance of $90 per day in each option. I chose this per diem allowance after reviewing New England per diem rates in the United States Internal Revenue Service document: “Publication 1542 Per Diem Rates” (Rev. October 2007). My per diem allowance is based on the assumption that two pipeline contractor demolition workers would share one room (1/2 of the maximum lodging allowance) and includes a full allowance for meals and incidental expenses for each worker. Typically, contractors must pay per diem allowances to their employees to compensate them for working in areas far from their home base.

Q.31 What equipment rates did you use in each option?

A.31 I used the equipment rates listed in the Construction Equipment Ownership and Operating Expense Schedule, Region I, published by the U.S. Army COE, July 2007 and escalated these rates to December 2007 using ENR construction cost indices. Region I includes the northeastern U.S. Hourly equipment rates are included in this publication for contractor owned and operated equipment working in “average” or “severe” conditions. I assumed “average” operating conditions for my cost estimates, based on Appendix C of this publication entitled “Guide for Selecting Operating Conditions” and upon my knowledge of PNGTS’ transmission facilities. Exhibit No. PNG-18, page 67 is a summary of the equipment rates that I used in each option.

Q.32 What factors did you employ in each option to reflect the indirect costs incurred by pipeline contractors?

A.32 The indirect cost factors used in each option for pipeline contractors include a 5-percent factor for mobilization, a 15-percent factor for overhead, and a 10-percent factor for profit. These indirect cost factors are based on my past experience and knowledge of the construction industry. I believe they are a reasonable reflection of the indirect costs a prudent contractor and owner would expect to incur during a pipeline retirement of this scale.

Q.33 How did you develop the equipment and labor spread and estimate the time needed to carry out specific demolition activities in each option?

A.33 I relied on my past experience and judgment gained from performing first-hand estimates as a highway engineer and developing and analyzing abandonment estimates of regulated gas pipeline, oil pipeline, and electric companies including the 2001 PNGTS final abandonment estimate developed by Parsons.

Q.34 Mr. Taylor, did you include environmental costs in each option?

A.34 Yes. Each pipeline retirement line item contains a factor based on five percent of pipeline contractor costs to allow for the costs of monitoring the final abandonment activity, conducting tests for hazardous materials, and writing reports. In addition, as discussed earlier in my testimony, estimated site restoration costs are included in pipeline contractor costs when required. I did not include any provisions in my options for handling and disposing of hazardous materials.

Q.35 Similarly, did you include an allowance for pipeline company inspection in each option?

A.35 Yes. Each pipeline retirement line item that involves demolition work includes an allowance of $500 per day per pipeline company inspector for monitoring the retirement activities. This allowance includes labor, per diem, and transportation costs.

Q.36 Did you also include an allowance for PNGTS management and overhead costs in each option?

A.36 Yes. A PNGTS management and overhead factor, based on 15-percent of pipeline contractor costs, environmental costs, and pipeline company inspection costs, is included in pipeline retirement line items to allow for the costs to manage and carryout the project. The 15-percent factor that I used for PNGTS management and overhead is the same as the level of overhead that I used in developing pipeline contractor costs as discussed earlier in my testimony. The 15-percent PNGTS management and overhead factor includes the following cost items: project management, FERC abandonment application, miscellaneous permits, engineering, construction management, ROW, project security, and general and administrative overhead. My review of cost information in Commission Docket CP96-249, Portland Natural Gas Transmission System, indicates that a 15 percent PNGTS management and overhead factor is reasonable for use in each option.

Q.37 Do you anticipate significant ROW costs during final abandonment?

A.37 Yes. First, ROW easement holders must be notified in writing of the final abandonment. Second, legal documents must be drafted and executed to transfer full use of the ROW back to the easement holder. Third, PNGTS and its contractors must obtain permits to work in the ROW; remove pipe, M&R stations, and remote valves; grout crossings, etc.

ROW notification costs, legal costs, and permit costs described above are included in my 15 percent allowance for PNGTS management and overhead costs in each line item.

In addition to the ROW costs discussed above, pipeline contractor demolition activities during final abandonment work would result in damage payments to affected ROW holders. Due to the potential magnitude of ROW damages when significant quantities of pipe are removed, I used a damage payments allowance of $4 per foot in my line item, “Pipe removal”. My damage payments allowance is based on my review of ROW damage costs in the 2001 Parsons estimate and a review of actual ROW damage costs reflected in Commission Docket, CP03-43-000, Texas Eastern Transmission, LP.

Q.38 Did you consider salvage in each final abandonment option?

A.38 Yes. I included gross salvage allowances for valves, pipe, and line pack. I estimated that gross salvage for carbon steel used in valves and pipe would be $160 per ton at the work site, which is approximately 60 percent of the current value of carbon steel scrap at the scrap yard. The reduced gross salvage value at the work site takes into consideration the cost of preparing the material for shipment to the scrap yard and the cost of transporting the material to the scrap yard.

I estimated line pack salvage based on my assumption that line pack would be recovered until pipeline pressure reaches 200 psig at which point the pipe would be blown-down. Recoverable line pack was priced at $7.53 per Dth which was the spot price of natural gas at Dracut, Massachusetts on December 31, 2007. My line pack salvage calculations are shown in Exhibit No. PNG-18, page 65. Supporting line pack calculations are shown in Exhibit No. PNG-18, pages 76-78.

Q.39 Please comment on the 10 percent contingency used in each option.

A.39 I believe my 10 percent contingency is at the low end of the range of contingencies used in similar final abandonment estimates.

Q.40 Mr. Taylor, how would you characterize your recommended Option III final abandonment estimate?

A.40 I believe my Option III final abandonment estimate is conservative-low. As discussed earlier in my testimony, Option III is the most realistic of my three options and is near the lower end of the range of estimated PNGTS final abandonment costs. Option III contains provisions for removing approximately 9% of wholly-owned pipe and 13% of jointly-owned pipe. However, should ROW easement holders balk at accepting liability for pipeline abandoned on their property, PNGTS would have to negotiate with these easement holders to absolve PNGTS from future liability or take steps to remove additional transmission pipeline from the ROW. Either way, this would raise the cost of final abandonment considerably.

Q.41 Mr. Taylor, does this conclude your prepared direct testimony?

A.41 Yes, it does.