Large Filing Separator Sheet

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- Third-party damage is the major cause of "hits" on the gas distribution system. While new one-call systems and more rigorous enforcement have helped with this issue, there are technology needs in this area. Despite 20 years of research, we are still unable to reliably locate buried plastic pipe under all types of soil and moisture conditions. (According to A.G.A. Gas Facts (2005 Data), there are over 20,700 miles of plastic gas mains in Ohio.) Tracer wire laid above the pipe is helpful but, since it can corrode or break, locating plastic pipe by tracer wire is not always reliable.

- The guided horizontal boring tools described earlier are guidable from point to point as well as steerable; however, they still cannot "see" in front of themselves underground. The ability to locate sewer pipes, utilities and other obstacles is still an important and unresolved safety issue.

- After third-party damage, other areas of concern in distribution systems involve the issue of corrosion of steel pipe, especially bare steel. In Ohio, according to A.G.A. Gas Facts (2005 Data), there are 8,280 miles of bare, cathodically unprotected steel mains.

- Infrastructure Security is at the forefront of national attention following the events of 9/11. R&D in this area is still uncharted; yet the "cyber" and physical security of our natural gas infrastructure is critical to gas consumers and the national interests.

- Environmental issues surrounding old manufactured gas plant sites will cost millions of dollars to clean up. The ability to rapidly detect PCB's that may be in gas systems is another environmental challenge.

- End-use programs that are under development but which will not be able to proceed without continued funding include a low-cost, fully condensing residential water heater which is over 92% efficient, a residential heating-only absorption-based gas heat pump with a heating COP of 1.4, and an industrial/commercial super-boiler with efficiencies over 94% and NOx levels less than 5 ppm currently being funded by DOE as a laboratory sub-scale pilot project. The super boiler has entered limited field testing, but additional funding is needed.

- As new sources of methane enter the country, either through renewable resources like biogas or from liquefied natural gas (LNG) from abroad, issues of interchangeability and its impact on end-use equipment performance and gas system integrity need to be examined.

- The impact on the U.S. natural gas industry of potential global climate change initiatives has not yet been determined. While methane produces much less CO2 per MMBtu than either coal or oil, it has a high global warming potential, over 21 times the impact of a CO2 molecule, so initiatives to further reduce leaks in natural gas systems may be called for. So while costs for meeting global climate change goals will more heavily impact the (heavily coal-based) electric utility industry, the gas industry will also be affected, and additional R&D will be needed in this area to keep the costs of meeting CO2 reduction goals reasonable.

V. PLANNED R&D FOR DEO

Q18. What specific types of research projects does GTI expect to perform on behalf of DEO and its customers?

A18. While the choice of specific projects is up to DEO, there are at least ten R&D projects GTI is planning which DEO has expressed interest in funding in order to increase safety, enhance integrity and minimize escalation of O&M costs.

Q19. Please describe these projects.

A19. These projects are as follows:

(1) *Miniature Methane/Ethane Detector for Leak Surveys*: Previous gas-industry-sponsored work has resulted in the development of optical methods of finding gas leaks by detecting methane and, more recently, ethane. The presence of ethane in a gas leak positively confirms that the leak is related to natural gas, and not "swamp gas" or other sources of methane. This confirmation eliminates the cost of gas sampling and analysis, minimizes disputes among producers and suppliers, thus reducing the cost of operations. However, detection of very low levels of ethane in natural gas leaks is very challenging. An ethane capable modulator ("EMD") (approximately one cubic inch in size) is currently under development. The next logical step in the EMD development is to miniaturize other components of ethane detection and integrate the ethane system into a portable methane detector being developed under a separate project.

(2) *Hand-Held Acoustic System for Plastic Pipe Location*: Detection of underground plastic pipe is particularly challenging, especially when the tracer wire (placed over the

plastic pipe when it is buried) is no longer functioning. Plastic pipe is virtually undetectable using current pipe locating technology based on electromagnetic signals as it does not respond to such signals. In this project, the laboratory-grade acoustic pulse-echo pipe location system will be designed into a hand-held system for application to buried pipe detection. The system will be tested with participating utilities for detecting buried pipes, 1 to 6 inches in diameter at depths from 6 inches to 10 feet. The data collected at each location will require less than two minutes and the analyzed data will be displayed to the system operator.

(3) *Remote Laser Leak Surveys*: Current leak surveys of natural gas distribution systems involve use of "flame packs" and the mobile Optical Methane Detector ("OMD"). Both of these leak location technologies require that the detector be brought in contact with the gas leakage plume, a very labor-intensive effort. The Laser Line-scan Camera ("LLC") technology being developed under the on-going GTI-managed, utility-sponsored project with Laser Imaging Systems, Inc. and AVISYS, Inc. allows "stand-off" inspection of both mains and service lines out to distances of 30 meters from a moving vehicle. The primary objective of the proposed project is to evaluate/improve the detection limit and inspection speed of the LLC, and to make the system more user-friendly

(4) *Integration of Electromagnetic and Acoustic Obstacle Detection Systems for Utility Construction Operations*: The use of horizontal boring systems has simplified the placement of underground gas and other systems. However, existing horizontal boring tools are "blind," that is, unable to "see' in front of them, leading to the potential for penetration of sewer line laterals by gas systems, and penetration of gas lines by third-party contractors. This project focuses on integrating the drill-head mounted

electromagnetic ("EM") obstacle detection sensors under development at Maurer Technology, Inc. with the surface deployed acoustic sensors being developed by Folsom Research, Inc. The objective of these projects is to provide real-time detection of underground utilities during horizontal directional drilling operations during installation of pipes. The warning and detection circuitry would be electronically tied to the drill string rotation and forward advance controls so the drill string can be automatically stopped before a strike can occur. By combining these two technologies into a single, integrated display it would be possible to successfully detect buried, energized cables, as well as steel, plastic, clay and concrete pipes.

(5) *Product Development of an Obstacle Detection System Using Ground Penetrating Radar ("GPR")*: Currently there are no commercial instruments available to sense the presence of obstacles in the vicinity of a horizontal directional drilling ("HDD") bore used for installation of pipes. In the on-going project with Vermeer Manufacturing Company under the sponsorship of GTI, a new advanced GPR system, mounted on the drill head of an HDD that is capable of detecting obstacles in the proximity of the bore is being developed. It is expected that this initial on-going project will provide a pre-production system suitable for only one size HDD machine. This new GPR offers a step forward in the detection of obstacles in the HDD operations. The objective of the proposed work is to produce a fully commercial version of the drill head mounted GPR applying the results of the past developments. This project is a parallel path effort with project (4) to solve this critical underground utility challenge.

(6) *Inspection Platforms for Unpiggable Lines*: In response to a number of significant pipeline incidents in recent years, the federal government has imposed new requirements

on gas transmission pipeline operators to assess the condition of their facilities. One of the methods used to examine a transmission pipeline is in-line inspection ("ILI"), also known as "smart pigging." Many transmission pipelines are designed to accommodate pigs. Similar requirements are expected within the next few years for LDC-owned transmission pipelines that do not fall under the current requirements. Unfortunately, the majority of LDC-owned transmission or higher pressure lines contain short-radius bends, plug valves and other obstacles that render them unpiggable with traditional pigging devices. This project will develop an ILI device that can move through gas mains of variable diameter, be able to negotiate plug valves, and go around 90 degree bends.

(7) *Safe Reliable Operation and Maintenance of Aldyl A Plastic Gas Pipe Systems*: Plastic pipe was introduced to the natural gas industry in the early 1960's. With its many advantages over steel pipe (including lower cost, lighter weight, easier handling, speedier installation and joining, no corrosion problems, and no welding), it quickly became the material of choice for gas distribution systems. Some of these early materials have, and continue to, perform well. However, significant technology improvements since the 1960's have made the current generation of plastic piping materials highly rugged and reliable, with many types of plastic piping having estimated life expectancies in excess of fifty years. While new plastic pipe materials perform very well, some of the early materials could be problematic under certain applications. This project has as its intent the identification of specific problems and issues associated with the use of Aldyl-A pipe systems (pipe and fittings).

(8) *Alternative Methods for Pavement Cutting*: Most of the current pavement cutting and restoration procedures use jackhammers, pavement saws, and backhoes for cutting and

moving the asphalt and concrete layers. These methods are noisy, restricted to daylight operation, produce a risk of injury, and can cause damage to adjacent uncut pavement. This project focuses on evaluating alternatives to these methods with the objectives of eliminating the drawbacks of existing methods and presenting improvements in efficiency and cost-effectiveness.

(9) *Micro-Excavation System Applications*: Keyhole excavation has enabled street repairs through much smaller (about 18 inches in diameter) openings, reducing the cost and time required for typical maintenance and repair challenges. This project has as its intent the development of equipment, tools, sensors, materials, and procedures to access, examine, and maintain buried pipe through two, two-inch diameter excavations.

(10) *Service Applied Main Stopper*: This project focuses on lowering the costs associated with emergency gas shut-off due to third-party damage, through the development of an innovative tool and method of use. Current field practices to isolate the damaged section of pipe involve multiple excavations to set stopping or squeeze-off equipment as well as multiple customer shut-offs. By inserting a stopping device through the customer's meter valve, crews can isolate the damaged section between neighboring customer service lines and stop the flow of gas. Developing this technology will resolve two major issues: (1) the costs associated with third-party damage repairs and (2) the ability to isolate and stop a ruptured gas main.

Q20. How will the projects you have just discussed be prioritized?

A20. DEO will provide the authorization as to where their research-funding dollars are applied from the list of candidate projects.

VI. COST RECOVERY OF GTI CHARGES

Q21. Why should the Commission allow DEO to recover from ratepayers charges paid to GTI?

A21. Over the past twenty-five years, gas consumers have realized billions of dollars of benefits from GTI's R&D. As shown in Attachment RE 7.1, overall consumer benefit-to-cost ratio is 8:1, including all R&D costs and benefits from commercialized products and services. Based on our over twenty-year track record of maintaining benefit-cost ratios of over 8:1, it is reasonable to expect that during the test year and beyond, GTI can sustain this benefit-to-cost ratio for Ohio gas consumers.

The guidance from public utility commissions and LDCs as well as others, such as consumer advocates and environmental groups, will ensure the selection of specific R&D projects that are appropriate to and offer benefits for Ohio gas consumers.

Continuation of GTI's R&D programs is absolutely critical for the continued supply, transport, and affordable use of natural gas as a current and future environmentally benign, domestically produced energy source for Ohio and for the United States.

Q22. Have other state commissions allowed LDCs to recover charges paid to GTI from ratepayers?

A22. Yes. There are 22 states currently authorizing research funding for gas-consumer-interest R&D for one or more of the LDCs in their state. These are Alabama, Arizona, California, Delaware, Florida, Idaho, Illinois, Kentucky, Mississippi, Minnesota, New York, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Oklahoma, Oregon, Pennsylvania, Virginia, Washington, and Wyoming.

Q23. What level of funding is GTI seeking from local distribution companies that are coming before their state jurisdictions to request rate increases?

A23. GTI is recommending that revenues equivalent to 1.74 cents per MMBtu be collected from DEO customers in its Ohio service area. The 1.74 cents is also consistent with the FERC approved charge from the GTI R&D program up until 1998, when parties agreed to reduce and then eliminate the FERC-approved charge. DEO is requesting recovery of $600,000 to be collected for R&D, less than 20% of the prior (1.74 cent) FERC R&D surcharge.

Q24. Does this conclude your testimony?

A24. Yes it does.

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Benefits of GRI RD&D Results That Have Been Placed in Commercial Use in 1999 Through 2003

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Abstract

This report provides brief descriptions for sixteen new GRI RD&D products commercialized in 2003 and two enhancements of previously introduced products. The economic benefits are quantified for eighty-one items commercialized between 1999 and 2003 that are known to have produced significant economic benefits for their users. The calculated ratio of the benefits to gas customers to total GRI costs incurred in 1999 through the end of 2003 was 8.0 to 1.

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Introduction

Between January 1, 2003 and December 31, 2003, sixteen GRI RD&D results were placed in commercial service. In addition, enhanced versions of two previously commercialized items were placed in use*. Those items are listed in Table 1, and brief descriptions of the eighteen items are included in Appendix A. With these new additions, some 133 GRI RD&D results have entered the commercial marketplace during the 5-year period between January 1999 and December 2003. The full list of the 133 items is included in Appendix B. As one measure of the value of the GRI RD&D program, the economic benefits accruing to users of 81 out of the 133 products can be compared to the total outlays of GRI during the past five years. This paper highlights the new GRI products that have entered the market during the past year and presents the results of the benefit-to-cost analysis of GRI's RD&D results during the past five years.

Notable additions to the list of GRI RD&D results placed in commercial service in 2003 include:

- Upgrades to the National Fuel Gas Code relating to the requirements for combustion air supply and corrugated gas vent connectors.
- A software tool to estimate critical information such as annual or monthly loads and costs associated with air-conditioning, heating, and on-site power generation for commercial buildings.
- A low-NO_x, high-heat-transfer industrial burner that provides significantly higher heat transfer to furnace loads, higher furnace efficiency, and lower flame and combustion products temperature.
- Paralleling switchgear for distributed generation systems that reduces the barriers to installing gas-fired DG equipment.
- A report on the safety of vacuum excavation equipment used to remove soil from holes that are being dug by distribution companies.
- Evaluation of alternate methods for removing cyanide wastes from former manufactured gas plant sites.
- A chemical fingerprinting methodology for enhanced environmental forensic analysis to characterize complex manufactured gas plant wastes.
- A software package to evaluate potential adverse environmental effects of pipeline crossings of streams.
- Technology to improve the quality of the cement used to seal the annulus between the casing and surrounding rock in gas wells.
- Development of produced water atlases for 10 major gas-producing states and a handbook on actual produced water management practices and disposal economics for 26 basins.
- A comprehensive report on the gas potential of the Lewis shale formation of the San Juan Basin in Colorado and New Mexico.

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* For tangible products (hardware, software) we interpret "commercialized" to mean that the product is commercially available, economically viable without subsidies, and has been sold in meaningful quantities. For the less tangible reports and other information products, we require that the products have been used in a commercial enterprise and have generated demonstrable economic benefits to the users. "Enhanced" products have been augmented in a commercially significant way, with or without GRI support. The augmentation may be a technical improvement in a product line, expansion of a product catalog, or expansion of the product market into new areas not available to the original product at its time of introduction.

Table 1. GRI RD&D Results That Have Been Placed in Commercial Use in 2003

RESIDENTIAL
1. Upgrades to the National Fuel Gas Code

COMMERCIAL
2. Building Energy Analyzer™

INDUSTRIAL
3. Low-NO_x Combustion System for Glass Furnaces *
4. Low-NO_x, High-Heat-Transfer Burner
5. LNG Interchangeability in Burners

POWER GENERATION
6. Distributed Generation Switchgear
7. Guidebook to Gas-Fired Distributed Energy Technologies

DISTRIBUTION
8. Safety of Vacuum Excavation Operations
9. Gas Distribution Construction Guide
10. Removing Cyanide Wastes from MGP Sites
11. Chemical Fingerprinting for Enhanced Environmental Forensic Analysis

PIPELINE
12. Gas Leak Measurement Device (Hi-Flow® Sampler) *
13. Environmental Effects of Pipeline Crossings of Streams
14. Standard for Coriolis Meters

EXPLORATION AND PRODUCTION
15. Cement Pulsation Technology
16. Analysis for Radium in Marine Sediments
17. Produced Water Atlases and Handbook
18. Gas Resource and Production Potential of the Lewis Shales

* Enhancement to a previous product.

Benefits Results

Between January 1999 and December 2003, one hundred and thirty-three GRI RD&D results were placed in commercial service. The full list of the 133 items placed in commercial use is included in Appendix B. This report focuses on evaluating the benefits of 81 of the 133 GRI RD&D items that are known to have produced significant *quantifiable economic* benefits for their users. The 81 items are listed in Table 2. Benefits to product users in typical applications were calculated by comparing the economics of the GRI-sponsored products with the economics of products that would have been used in the absence of the GRI product. Product cost and performance data were obtained from product vendors, from field test results, or from product users. The measure of product benefit is the net present value of the incremental cash flow to the user (cost savings minus incremental cost) over the product lifetime using a real discount rate of 5% (above inflation). The GRI Baseline[1] national average projections of energy prices were used, when appropriate, to estimate cost savings. Total benefits were calculated by multiplying the unit benefits by the sales projected by product vendors from the first year in which the product was sold through 2008. The results are shown in Table 2. A range of product sales is shown to protect proprietary vendor sales projections.

As shown in Table 2, calculated economic benefits for the 81 items are estimated to be between $3.4 and $5.9 billion. Table 3 shows the expected value of benefits, at about $4.9 billion, and the breakdown of the economic benefits by sector. We estimate that the 81 items account for most of the economic benefits that would be calculated for the entire set of 133 products. Omitted items often offer significant benefits to their users, but have not achieved widespread use as have the 81 high impact items. In addition, some of the omitted items are designed to produce benefits that are not easily expressed in economic terms. For example, RD&D results provide test methods for new gas equipment, technologies to meet existing or anticipated air emissions requirements, and information that is useful to the gas industry in developing gas resources and delivering the gas to consumers.

[1] P.D. Holtberg, J.C. Cochener, "Baseline Projection Data Book: 2001 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2020," GRI-01/0002.1 and GRI-01/0002.2, GRI, March 2001.

Table 2. Summary of Benefits of GRI RD&D Results That Have Been Placed in Commercial Use in 1999 Through 2003

	Sales or Applications Projected Through 2008 (in units)			Year of First Sale	Net Present Value of Benefits** (Million 2003$)		
RESIDENTIAL							
Upgrades to the National Gas Fuel Code		***		2003	$62.5	to	$109.3
COMMERCIAL							
kitchenCOST™ Software	545	to	1,000	1998/99	$37.3	to	$68.5
Modulating Indirect-Fired Make-Up Air Unit with Clean Modulation	1,800	to	3,300	1999	$6.4	to	$11.8
GATC: AERCO Benchmark Boiler	1,350	to	2,700	1999	$26.5	to	$53.0
PITCO Gas Fryers	75,000	to	138,000	1999	$45.7	to	$86.6
AUTOFRY™ Deep Fat Fryer	2,130	to	4,260	1999	$8.1	to	$16.2
York 600 RT 134a Chiller	60	to	95	2000	$32.7	to	$51.3
Tecogen 150 RT 134a Chiller	65	to	105	2000	$2.2	to	$3.6
INDUSTRIAL							
Process Application of Composite Radiant Tubes	39,600	to	68,600	1994/99	$66.6	to	$115.4
High Performance Infrared Burners	125	to	190	1995/00	$612.27	to	$918.40
Natural Gas Cofiring in Biomass-Fueled Stoker Boilers	13	to	20	1999	$103.9	to	$163.3
Ultra-Low-NOx Boiler Burner	120	to	180	1999	$62.1	to	$93.1
METHANE de-NOX® Reburn Technology	6	to	11	1999	$136.2	to	$233.5
Forced Convection Heater (FCH) Systems – Automotive	11	to	19	2000	$14.2	to	$23.6
Oscillating Combustion Burner	125	to	225	2001	$17.0	to	$30.4
Low-NO_x Combustion System for Glass Furnaces	11	to	21	1995/03	$69.7	to	$127.9
Low-NOx, High-Heat-Transfer Burner	170	to	300	2003	$31.6	to	$56.5
POWER GENERATION							
IR PowerWorks Microturbine Cogeneration Systems	2,600	to	4,000	2000	$50.2	to	$78.9
Advanced High-Output Gas Engine-Generator (Caterpillar 3500® Series)	40	to	60	2001	$12.6	to	$21.6
Distributed Generation Switchgear		***		2003	$3.0	to	$4.7
TRANSPORTATION							
NGV Cylinders Types 1 and 2	28,500	to	69,700	1999	$5.5	to	$13.4
Advanced NGV Fueling Dispenser	80	to	170	2002	$1.2	to	$2.6
DISTRIBUTION							
Plastic Pipe Across (and on) Bridges	4,125	to	8,660	1995/99	$63.2	to	$132.8
DrillPath™ Software for Directional Drilling Operations	110	to	160	1996/99	$2.4	to	$3.6

	Sales or Applications Projected Through 2008 (in units)			Year of First Sale	Net Present Value of Benefits** (Million 2003$)		
Starline® 2000 Renewal Technology	135,300	to	248,000	1999	$1.9	to	$3.5
Guided Mole	20	to	40	1999	$4.6	to	$8.0
Gas Holder Manual of Practice	7	to	12	1999	$6.3	to	$11.5
One-Step Paving	230	to	430	2000	$3.4	to	$6.7
Soil Compaction Supervisor	470	to	820	2000	$19.4	to	$33.9
Self-Loading, High-Efficiency Trailer for Coiled PE Pipe	22	to	43	2001	$70.8	to	$141.7
Cold-Mix Restoration of Pavement Cuts	130	to	330	2001	$9.4	to	$24.4
Imaging Underground Utility Structures	900	to	1,650	2001	$6.4	to	$11.7
Comparative Evaluation of PE Pipe Materials	55	to	110	2001	$50.1	to	$100.3
Directional Drilling for Plastic Pipe under Railroad Crossings	46	to	100	2001	$12.6	to	$27.2
PE LIFESPAN FORECASTING™	135	to	250	1994/01	$83.7	to	$154.9
Pipe Splitting Tool	15	to	30	1998/02	$9.5	to	$19.0
Gas Distribution Cost Database	450	to	800	2002	$11.8	to	$21.0
Assessment of PVC Pipe	4,300	to	9,500	2002	$20.0	to	$44.1
Plastic Pipe Informational Web Site		***		2002	$4.3	to	$7.9
Worker Exposure to Hazardous Substances		***		2002	$5.4	to	$16.2
Safety of Vacuum Excavation Operations	50	to	160	2003	$2.6	to	$8.3
Gas Distribution Construction Guide	22,500	to	54,000	2003	$2.9	to	$6.9
Removing Cyanide Wastes from MGP Sites	6	to	14	2003	$4.6	to	$11.9
Chemical Fingerprinting for Enhanced Environmental Forensic Analysis	185	to	290	2003	$49.5	to	$77.8
PIPELINE							
Breeze Haz™ Environment and Safety Offsite Consequence Modeling Software	3,000	to	5,300	1999	$14.0	to	$24.4
Emeritus Report B31.8 Code, Federal Pipeline Safety Regulations		***		2000	$19.2	to	$57.7
Elastic Wave Vehicle Tool		***		2000	$67.6	to	$146.5
API 14.1 Gas Sampling Standard.	5	to	11	2001	$5.0	to	$10.9
Ultrasonic Meter Installation Effects	2,500	to	5,000	2001	$65.4	to	$130.7
Orifice Meter Operational Effects	20	to	40	2001	$38.0	to	$70.7
DamageExpert™ Software	35	to	75	2001	$61.4	to	$133.0
Satellite Radar Interferometry Measurement of Slope Movement	20	to	45	2001	$48.8	to	$105.8
AIRCalc™ Software	145	to	265	2001	$79.4	to	$145.5
Predicting the Integrity of Storage Caverns in Thin Salt Beds	3	to	9	2002	$0.4	to	$1.2
ASME Standard for Pipeline Integrity Management		***		2002	$5.0	to	$10.8
NACE Standard for Direct Assessment of Pipeline Corrosion		***		2002	$0.7	to	$1.7
Reference Manuals of Best Practices for Horizontal Directional Drilling and its Effect in Wetlands	75	to	250	2002	$2.0	to	$6.5
Best Environmental Practices for Pipeline Construction	600	to	1,200	2002	$2.6	to	$5.2

	Sales or Applications Projected Through 2008 (in units)			Year of First Sale	Net Present Value of Benefits** (Million 2003$)		
Gas Leak Measurement Device (Hi-Flow® Sampler)	30	to	120	2000/03	$4.6	to	$18.4
Environmental Effects of Pipeline Crossings of Streams	745	to	1,150	2003	$45.4	to	$71.3
Standard for Coriolis Meters	115	to	230	2003	$6.2	to	$12.4
EXPLORATION AND PRODUCTION							
Unconventional Natural Gas Database	110	to	190	1999/01	$10.4	to	$18.3
Downhole Gas/Water Separation CD-ROM	75	to	130	1999	$8.8	to	$15.2
Advanced Crosswell Seismic Source	200	to	400	1999	$33.7	to	$66.8
High Power VSP Mechanical Seismic Source	520	to	750	1999	$25.4	to	$37.0
Advanced Stimulation Technologies CD-ROM	45	to	80	1999	$5.5	to	$10.0
Coiled Tubing Standards	3	to	5	1999	$15.7	to	$30.3
GRI–MSTR™ Software and Report to Predict Toxicity of Produced Water Discharged to the Marine Environment	280	to	440	1999	$12.5	to	$19.7
Glycol Dehydrator Emissions Calculation Program - GLYCalc™ 4.0	720	to	1,330	1992/00	$76.0	to	$140.7
ProTreat™ Software for Amine Gas Treating Applications	45	to	75	2000	$136.1	to	$226.9
Cased Hole Resistivity Tool	800	to	1,300	2000	$12.3	to	$20.0
Cased Hole Pressure Tool	725	to	1,245	2000	$106.5	to	$182.6
Well Siting in Carbonates – EGI Report	90	to	140	2000	$72.2	to	$108.3
Portfolio of Emerging Natural Gas Resources – Rocky Mountain Basins	480	to	720	2000	$110.6	to	$165.9
Mercury Contamination Training Workshop	300	to	500	2000	$3.0	to	$5.1
New Gas Exploration Concepts	65	to	100	2001	$280.8	to	$441.2
StreamAnalyzer™ Software	370	to	820	2001	$80.3	to	$176.6
Enhanced Seismic Spectral Processor	200	to	330	2002	$35.0	to	$56.8
Cement Pulsation Technology	670	to	1,340	2003	$23.9	to	$47.9
Analysis for Radium in Marine Sediments	12	to	24	2003	$3.3	to	$6.6
Gas Resource and Production Potential of the Lewis Shales	45	to	70	2003	$32.1	to	$48.2
TOTAL (million of 2003 dollars, 5% discount rate)					$3,402		$5,934

* Enhancement to a previous product for a new market application.

** Net present value calculations based on a real discount rate of 5% (excluding inflation), stated in 2003 dollars.

*** Benefits are based on user feedback about technical and market influence of the RD&D items.

Table 3. Total Expected Benefits by Sector

	Quantified GRI RD&D Results	Net Present Value of Benefits (Million 2003$)
• Residential	1	$104
• Commercial	7	$256
• Industrial	9	$1,360
• Power Generation	3	$94
• Transportation	2	$15
• Distribution	22	$760
• Pipeline	17	$772
• Exploration and Production	20	$1,582
TOTAL	81	$4,943

GRI RD&D Costs

Between January 1999 and December 2003, GRI outlays totaled $530 million. For comparison to the RD&D benefits calculated above, the cost cash flow stream was converted to an equivalent net present value lump sum expenditure at the beginning of 2003. As with the benefits calculation, a 5% real discount rate was used in the net present value calculation. The calculated equivalent cost was $619 million. These costs include all outlays made by GRI during the past 5-year period, not just the costs incurred to produce the 133 RD&D products. Consequently, a portion of the calculated cost will yet generate benefits as additional products are commercialized in the future.

Benefit-to-Cost Ratio

Dividing the calculated benefits by the costs results in a calculated benefit-to-cost ratio range of 5.5 : 1 to 9.6 : 1 (benefits of $3.4 to $5.9 billion divided by outlays of $619 million) with an expected value of 8.0 : 1 ($4.94 billion divided by $619 million). In a similar analysis carried out in 2003 for RD&D items placed in commercial use between 1998 and 2002, the calculated ratio of the benefits to gas customers to total GRI costs incurred during the same period was 8 to 1[2].

Conclusions

GRI's planning and budget allocation process strives to put in place a program with the maximum ratio of benefits to RD&D costs for the mutual benefit of the gas customer and the gas industry. The economic evaluation of GRI's commercially successful RD&D results have consistently shown that benefits far exceed the costs of the RD&D program.

Analysis of the benefits of approximately 81 of the 133 GRI RD&D items placed in commercial service between January 1999 and December 2003 shows that GRI RD&D will return about $8.0 for every dollar invested in GRI during the same period. In addition to the fact that only a portion of GRI's commercialized

[2] A.D. Bournakis, " Benefits of GRI RD&D Results That Have Been Placed in Commercial Use in 1998 Through 2002," Gas Research Institute, May 2003, GRI-03/0106.

RD&D items are included in the benefits calculation, all of the costs of GRI's operations during the 1999 to 2003 period have been included in the calculation of the benefit-to-cost ratio.

Appendix A
GRI RD&D Results That Have Been Placed in Commercial Use in 2003

RESIDENTIAL

Upgrades to the National Fuel Gas Code: GRI research led to recommendations for the 2002 National Fuel Gas Code (NFGC), published by the National Fire Protection Association in 2003, relating to the requirements for combustion air supply and corrugated gas vent connectors. These recommendations were intended to improve installation practices and energy efficiency. GRI's recommendations for appliance air requirements were to: 1) remove the designation of "unusually tight construction," because all new homes have what was previously considered unusually tight construction; 2) increase the required volume of rooms containing natural-draft gas appliances from at least 50 cubic feet per thousand Btu per hour of gas input to at least 52.5; and 3) specify a required volume of at least 37.5 cubic feet per thousand Btu per hour of gas input for rooms containing fan-vented appliances. GRI's recommendations for corrugated vent connectors were: 1) corrugated connectors to be equivalent to normal vent connectors and should both be oversized and have long-radius bends; 2) oversized corrugated connectors should be designed to avoid sudden expansions or contractions at the connections; and 3) flexible chimney reliners should have a design capacity 15% less than comparable Type B gas vents. The adoption of GRI's recommendations will allow greater flexibility in placing appliances in homes and will help reduce construction costs. Many installations that formerly required outdoor air to be ducted to the appliance will no longer require that expensive ducting.

COMMERCIAL

Building Energy Analyzer™: The Building Energy Analyzer™, developed by GRI, is a software tool that aids heating, ventilation, and air-conditioning (HVAC) professionals in tailoring economic analyses for several types of facilities. The program allows users to estimate critical information such as annual or monthly loads and costs associated with air-conditioning, heating, and on-site power generation for commercial buildings. The Building Energy Analyzer compares the performance of a wide variety of HVAC technologies, such as standard- and high-efficiency electric chillers, variable-speed electric chillers, absorption chillers, engine-driven chillers, on-site power generators, thermal storage, heat recovery, and desiccant systems. It estimates annual or monthly loads and costs associated with air-conditioning, heating, power generation, thermal storage and cogeneration systems for a given building and location. It performs quick-to-use economic analysis for the customer's utility rates, location, and building type. Additional features include: templates for each of the 15 most typical commercial building types; capability to handle complex utility rates; weather data for 233 cities; ability to perform life-cycle cost analysis on building cooling, heating, and power generation (BCHP) equipment. The software program is compatible with Windows® 95, 98, 2000, and XP and ME systems. Version 2.0 of BEA was released in 2003. The program with a complete manual in PDF format is distributed by GTI, with user support, maintenance, and upgrades provided through GTI's InterEnergy Software Project.

INDUSTRIAL

*** Low-NO_x Combustion System for Glass Furnaces:** Regenerative glass furnaces use extremely high air-preheat temperatures, which result in very high uncontrolled emissions of NOx. These furnaces are being placed under stringent regional and state regulations. GRI developed a furnace system that cost-effectively reduce NOx emissions from regenerative glass melters to less than 2.5 pounds per ton of glass. The new combustion technology, called oxygen-enriched air staging (OEAS), uses a unique method of introducing combustion air to control NOx formation. In a first combustion stage, the amount of combustion air through the firing ports is limited to decrease the oxygen available in the flame's high-temperature zone. This reduces NOx formation but leads to high concentrations of carbon monoxide and unburned hydrocarbons. Oxygen-enriched air is injected into the furnace in a second stage near the exit ports to complete the combustion. OEAS has been successfully retrofitted to endport container-glass furnaces with flint and amber glass production capacities of 135 to 320 tons per day. NOx levels were reduced by 50-70%. The OEAS technology has now been adapted to operate similarly on sideport furnaces, which are used for nearly 65% of U.S. glass production. Endport and sideport furnaces are similar in concept, but significantly different in physical design and flame characteristics. OEAS has been successfully retrofitted to seven endport container-glass furnaces and three sideport container-glass furnaces. NOx was reduced by 50 to 70% on endport furnaces, with no adverse impacts on other emissions, furnace performance, or glass quality. OEAS technology applied to three sideport furnaces reduced NOx by 40% to as much as 70%. GRI licensed OEAS technology to Combustion Tec, the glass division of Eclipse Combustion. In 2003, Combustion Tec began marketing OEAS for endport and sideport glass furnaces.

Low-NO_x, High-Heat-Transfer Burner: Two serious problems with high-temperature combustion processes, such as glass melting, are their intrinsically low efficiency and high emissions of NO_x. Efficiency is low because of the high energy content of the combustion products leaving the process. NO_x emissions are high because NO_x yield increases as combustion temperature increases. The use of recuperative heat exchangers to increase efficiency and the use of post-process NO_x emissions control equipment are costly solutions to the problems. Both problems could be mitigated by using oxygen instead of air to support the combustion. However, although oxy-gas firing has been implemented commercially to some extent, oxy-gas flames emit less thermal radiation than is desired for high process productivity. GRI developed a new oxy-gas burner that increases flame radiation by forming soot in the flame and then consuming the soot before it leaves the furnace. The High-Luminosity burner provides a preheating zone at the burner inlet to form soot, a fuel-rich flame zone to radiate heat to the furnace load, and a fuel-lean zone to burn out the soot. The soot radiation increases the effectiveness of heat transfer within the furnace and cools the flame, thereby reducing NO_x formation. The new burner provides significantly higher heat transfer to furnace loads, higher furnace efficiency, lower flame temperature, lower combustion products exit temperature, and significantly lower NO_x emissions. The high-luminosity burner can be used in conjunction with other NO_x reduction techniques, including combustion modifications and oxygen-enriched air staging. The burner is an easily installed, low-cost process modification that can, in oxy-fuel applications, increase process and energy efficiency by up to 10 percent while emitting 50 percent less NO_x than conventional oxy-gas burners. Test results showed a 4.5 percent increase in total heat transfer, which corresponds to a 10 percent decrease in fuel use. Combustion Tec Division of Eclipse™, Inc. licensed the technology and began marketing the burner to the glass industry in 2003 under the brand name Primefire® 400.

LNG Interchangeability in Burners: GRI evaluated the sensitivity of selected burners to compositions typical of LNG that is rich in heavier hydrocarbons. With LNG poised to play an increasingly important role in U.S. natural gas supplies, one of the issues of interest to the gas industry is the degree to which natural gas from LNG is interchangeable with pipeline quality gas in terms of its performance in combustion equipment, especially if heavier hydrocarbon components become more concentrated during handling. The heavier hydrocarbons would increase the density, heating value, and flame speed of the gas. If these increases are large enough, they may adversely affect the performance of some gas burners. The selected burners represent a variety of U.S. residential appliances. This study replicated previous methods that were used to study interchangeability to demonstrate their applicability to LNG, identified a set of indices that can be used to predict combustion behavior, investigated several ways to reduce the heating value of LNG, and related the performance of a specially designed test burner to the performance of a variety of residential appliances. The R&D determined interchangeability indices for natural gases used in the U.S. and for a range of anticipated world LNG imports to the U.S. It determined that, for the residential burners studied, expected LNG compositions are adequately interchangeable with U.S. pipeline gases if their heating value and density are suitably adjusted by dilution with air or nitrogen.

POWER GENERATION

Distributed Generation Switchgear: GRI developed paralleling switchgear for distributed generation (DG) systems that offer lower capital costs; plug-and-play simplicity; integration with leading natural gas engine-generator set manufacturers; conformity with basic electric utility interconnection requirements; conformity with existing or projected industry standards; and remote monitoring, communications, and control functions. Consolidating system functions reduced the number of components, and this reduction in components led to a smaller footprint, lower material costs, and less engineering. In addition to cost reduction, the new switchgear has more features, and this makes gas-fueled DG systems more attractive. The switchgear offers the widest array of communication capabilities found in DG systems today. The cost of switchgear was reduced from $75-$100 per kilowatt to $40-$60 per kilowatt. This was accomplished by reducing the number of components in the generator control section by 40-60%, reducing the space required for mounting the generator controls by 50%, reducing the engineering time by 30%, and reducing sheet metal and bus bar by 40-70%. The results of this R&D have significantly reduced the barriers to installing gas-fired DG equipment. The switchgear became commercially available from GE Zenith Controls in 2003 under the name Entellysis®.

Guidebook to Gas-Fired Distributed Energy Technologies: There has been an increase in interest in on-site generation of electric power systems, also known as distributed energy (DE) systems. DE systems that recover and use exhaust heat from the engines to provide other thermal needs at the site are called cogeneration systems or combined heat and power (CHP) systems. CHP systems offer users high energy efficiency (up to 80%) because they make heat available that would be wasted if the electric power were generated at a central power station. Although DE and CHP systems offer very high energy efficiencies, they have not had high market penetration. Potential DE and CHP users are not familiar with DE and CHP equipment performance and cost. To help overcome the lack of familiarity, GRI cooperated with the National Renewable Energy Laboratory (NREL) to publish a definitive guidebook on the performance and cost of the various prime mover technologies that can be used to generate power in DE and CHP applications. These technologies are reciprocating engines, small gas turbines, microturbines, steam turbines, fuel cells, and Stirling engines. The guide was published in 2003 and is available from NREL. It describes each of the six technologies, their power generation performance, cost, and emissions characteristics. Because some of the technologies have not yet been fully commercialized, the guide also predicts the performance and cost that the prime mover technologies will achieve in the future (2010, 2020, and 2030).

DISTRIBUTION

Safety of Vacuum Excavation Operations: Vacuum excavation involves the use of equipment to remove soil from holes that are being dug by distribution companies. Interest in using it has expanded greatly with the introduction of keyhole repair technologies, which depend on vacuum excavation. Keyhole repairs often encounter leaking gas in small spaces, and this has raised the question of whether vacuum excavation will pose unexpected hazards from ignition of gas-air mixtures in the vacuum hoses or the soil collection tank. Vacuum hoses are often made of plastic materials that are inexpensive and lightweight. Flow of air and solids through plastic pipes can create static electricity, which could be an ignition source. Flying rocks hitting the steel wall of the soil collection tank could also create sparks. GRI performed experiments designed with the deliberate goal of causing ignition. The experiments demonstrated that both high static electricity voltages and flammable gas-air mixtures can co-exist in the hoses and soil collection tanks without ignition occurring. A report, GRI-03/0128, "Vacuum Excavation of Potentially Flammable Gases," was released in September 2003. It gives gas companies confidence that vacuum excavation can be accomplished at least as safely as more traditional mechanical excavation. It is impossible to prove that ignition cannot occur under any condition that may occur during vacuum excavation. If gas company supervisors believe that there is an unacceptably high likelihood of gas ignition during a specific vacuum excavation operation, they can use aluminum-coated or other highly conductive vacuum hoses and ground both the soil collection tank and the hose. Small amounts of water can also be used to prevent static charge accumulation. The report also contains recommendations for maintaining safety during the use of suction techniques to remove water from flooded gas mains.

Gas Distribution Construction Guide: To help LDCs appropriately adopt new construction and repair technologies, GRI developed a Web site that describes many commercially available technologies that have been developed. It is called the Utility Construction Methods Selection Guide. The site covers many trenching and boring technologies for replacing deteriorating gas pipes, pipe lining technologies for pipe rehabilitation without replacement, and pipe bursting and splitting technologies for situations where lining is not feasible. In general, for each technology, the Guide contains the following sections: introduction, general description, advantages, limitations, technical application data, special considerations, application trends, U.S. utility experience, and contact information. The Guide describes six case studies in which trenchless or "no-dig" methods have been used for rehabilitating or replacing old and deteriorating gas mains and service lines. The six case studies cover the following six technologies: Amex® 2000, horizontal directional drilling, RENU™, starline®, Swagelining™, and U-Liner. Information on each case study is organized into the following sections: introduction, method applied, participating utility, application location, technical data, cost and savings data, economic analysis, and contact information. The Web site also contains an on-line economic calculator that compares various utility construction methods. Based on user inputs, the calculator selects appropriate rehabilitation or replacement methods for comparison. The analysis of the selected methods includes total installed cost, annual cost over the life of the project, net present value, and life-cycle cost. The Web site was put into operation in 2003 at www.gtiservices.org.

Removing Cyanide Wastes from MGP Sites: Cyanide compounds are found in the groundwater at many former manufactured gas plant (MGP) sites in the U.S. The cyanide compounds are residues of the manufactured gas purification process, which used iron-impregnated solid materials, such as wood chips, in purifier boxes to remove hydrogen sulfide from the manufactured gas. The iron compounds in the purifier box also removed some cyanide from the product gas. Spent iron compounds were often regenerated by spreading them on the ground. Some of the iron compounds remained in the soil and, upon contact with water, released cyanide compounds, which later entered the groundwater. Previous studies indicate that the dominant forms of cyanide compounds in purifier box wastes are iron cyanide complexes, which are highly stable in groundwater and resist natural decontamination by microorganisms. Current stringent limitations on allowable concentrations of cyanide in groundwater pose a compliance challenge. GRI evaluated alternate methods for removing iron cyanide complexes from the treatment plant effluent. The evaluation found that certain anion-exchange resins would adsorb the cyanide complexes, with a sorption capacity of up of up to 10% iron cyanide by weight. The resin functioned in the presence of high concentrations of sulfate ions, which interfere with the operation of most ion-exchange resins. GRI then developed a process based on the anion-exchange resins. The process was successfully demonstrated, at full scale, in an MGP waste treatment plant. It is recommended for treatment of water that contains up to 10,000 ppb of cyanide compounds. US Filter, in cooperation with GTI, is offering the process commercially.

Chemical Fingerprinting for Enhanced Environmental Forensic Analysis: Environmental forensic techniques are increasingly used to identify specific wastes, particularly at former MGP sites. However, currently, available analytical methods of environmental forensic techniques do not have enough conclusive discriminating power to insure scientific accuracy, reproducibility, and overall confidence in the use of chemical fingerprinting to characterize complex MGP wastes. These wastes, primarily dense non-aqueous phase liquid tars consisting of polynuclear aromatic hydrocarbon (PAH) compounds, are often aged, exceptionally dense, commingled with other wastes, and subjected to weathering over extended periods of time. With GRI support, the Gas Technology Institute has used chemical fingerprinting to successfully discern tar wastes from wholly different sources, and even to distinguish manufactured gas plant wastes from different plant operations. As a service to utility companies and others, GTI is providing fingerprinting, forensic engineering, and technical support for the identification of pollutants at particular sites, as well as for the study of process mechanisms. GTI takes a two-tiered approach in its environmental forensic services: The first is to characterize the discrete organic pollutants (e.g., BTEX, PAHs, PCBs, and endocrine-disrupting compounds) in water, soil, or sediment samples. These organic compounds all possess distinct "chemical fingerprints" which often can provide sufficient information to determine the origin(s) or source(s) of the contamination. The second tier is to characterize or "chemically fingerprint" the complex macromolecular organic matter in the sample matrix itself for signatures of various sources (e.g., natural, agricultural, industrial, and anthropogenic). Specifically, natural organic matter (NOM) is characterized for water samples, soil organic matter (SOM) is characterized for soil samples, and sediment organic matter (SdOM) is characterized for sediment samples. This technique has proven to be a sufficient monitoring tool that quantitatively compares changes in the organic quality of NOM/SOM/SdOM due to seasonal influence, changes in inputs or discharges, as well as treatment. Furthermore, the chemical fragments that are the reflection of these influences can be identified, quantified, and compared with other chemical and biological data to establish relationships.

PIPELINE

* **Gas Leak Measurement Device (Hi-Flow® Sampler):** GRI has developed an improved version of the Hi-Flow® Sampler, an inexpensive instrument for field measurement of leak rates. The Hi-Flow Sampler can be used to measure the rate of gas leakage around various pipe fittings, valve packings, and compressor seals in natural gas transmission, storage, and compressor facilities. It also measures background methane concentration in the air and automatically corrects the leak rate measurement for this background methane. The instrument is based on straightforward principles of dynamic dilution and concentration measurement. A very large, measured flow of air sweeps the area of the leak, completely capturing any gas leaking from the component being tested. The rate of the gas leak is calculated from the concentration of methane in the sweep air. The instrument is intrinsically safe for use in Class I hazardous locations. It has been approved by the Canadian Standards Association (C22.2 No. 157, June 1992), American National Standards Institute (June 27, 2002), and Underwriters Laboratories (UL913-2002). It provides data logging and instantaneous leak-rate display, and only minimal operator training is needed. *In 2003, Bacharach®, Inc. began marketing the Hi-Flow Sampler.*

Environmental Effects of Pipeline Crossings of Streams: Regulatory agencies have expressed concern about the environmental impact of pipeline water crossing construction on stream and river ecosystems. The main issue is the entrainment of sediment during pipeline construction and the effects of the sediment on downstream aquatic organisms. Because there were limited data and no field-proven predictive tools to quantify the effects of sediment released during water-crossing construction, assessment of impacts has been based on professional judgment and consideration of worst-case scenarios. This has led to the use of construction methods that were unnecessarily costly and often did not actually improve the degree of environmental protection. Because of the large number of pipeline water crossings and the large differences in cost among crossing methods, there was a need for scientifically defensible planning tools that allow industry to construct cost-effective, environmentally acceptable watercourse crossings. To meet this need, GRI developed CROSSING™ software and released it in 1998. It estimates how much the release of sediment during in-stream construction affects downstream fish communities. In 2003, CROSSING™ version 2.0, a more robust software package, was released. CROSSING™ 2.0 helps gas companies and regulators evaluate potential adverse effects of water crossing construction. This enables the selection of least-cost construction methods that satisfy environmental goals. Gas consumers will benefit from lower cost of pipeline service and from the prompt availability of pipeline service without delays in construction caused by unnecessarily extended permitting procedures.

Standard for Coriolis Meters: As part of its continuing search for better gas meters, the gas industry has become interested in using Coriolis meters in certain applications. Coriolis meters are of interest because they measure mass flow rate, which can be converted to a "standard" gas flow rate with only knowledge of the density of the gas at reference conditions. This is important because it avoids the need to predict the density of high-pressure gases with an equation of state and would avoid the errors associated with that prediction. Because of the mechanics involved in these meters, they are typically limited in size to pipe diameters less than 6 inches. Therefore, they would not be used for mainline meters, but would be used to measure gas flow to large customers or small municipalities. Manufacturers developed Coriolis meters for gas applications and reported the results of their development efforts, but no comprehensive, independent tests results were published. GRI evaluated the suitability of these meters for gas flow measurement, based on a test plan developed under the auspices of the American Gas Association. The tests verified that some of the meters that have been developed are accurate enough for gas custody transfer measurement. The results were incorporated into an American Gas Association report, issued in 2003. This report will serve as a standard for the gas industry. It provides a performance-based specification and test methods for Coriolis meters intended for natural gas flow measurement. It contains several appendices addressing theory, operation, accuracy, research, and test data.

EXPLORATION AND PRODUCTION

Cement Pulsation Technology: Cement is used to seal the annulus between gas well casings and surrounding rock, to insure that gas flows are taken from the intended formation, that the gas does not leak into shallower (lower pressure) formations, and that the gas is not contaminated with flows from other formations. It has been estimated that the cement in 20% of cemented wells on land fail within the first five years and as many as 65% of offshore wells fail within 15 years. Without remediation, the well may not reach its full gas production potential, and the annular leakage may present safety issues. GRI found that the quality of the cement structure can be improved significantly by vibrating the cement with pressure pulses transmitted from the surface immediately after cementing. Applying the pulses from the surface is less costly than the chemical additives that are now used to help reduce the occurrence of cement integrity problems. This low-cost technology will improve the ability of well cementing operations to seal gas zones. It will improve cement quality and decrease well repair costs. The pulsing technique was tested in 150 wells in gas fields that have been prone to gas leakage through the cement. An estimated $2 million in cement remediation costs was avoided. GRI's research included modeling to understand gas migration in cement and to study pulse propagation, technique effectiveness, and cement quality. In 2003 the technique was made commercially available in the U.S. by Reservoir Isolation Technical Services (RITS).

Analysis for Radium in Marine Sediments: Environmental concerns arose in regulatory agencies over the possible presence of naturally occurring radioactive materials in natural gas. Nuclear reactions of naturally occurring uranium and thorium in the rock of producing formations can form radium isotopes such as radium-226 and radium-228, which have long half-lives. In addition to long half-lives, these isotopes have long biological residence times because they incorporate into living skeletal material. They present health risks to gas industry workers because they may be deposited in gas processing equipment. To enable accurate assessment of possible risks, GRI investigated methods for determining the concentrations of these radium isotopes in produced water, fish, and sediments. The goal was to identify a reliable analysis method for measuring concentrations as low as 0.01 picoCuries per gram of material. Based on this information a method for inter-laboratory tests was developed. It was found that commercial radiochemical laboratories could obtain reliably accurate results with this method. In addition, a new, analytical method for seawater was evaluated and found to be accurate and sensitive to less than 0.01 picoCuries per gram. A report, GRI/01-0244, "Development, Evaluation, and Validation of Radioanalytical Methods for the Measurement of Radium 226 and 228 in Environmental Media Relevant to the Offshore Oil and Gas Industry," was made available in 2003 to gas production companies and service laboratories. The research results will help gas companies focus their remediation and control efforts on sites that pose true risks. This will enhance worker safety and reduce the overall cost of gas production.

Produced Water Atlases and Handbook: Changing environmental regulations and subsequent changes in permitting processes for produced water disposal are obliging oil and gas producers to modify their water treatment and disposal practices, often incurring higher costs. Surface discharge, which is the most economical strategy for produced water disposal, is no longer a viable option in many states where regulations have increasingly restricted the quality and quantity of water that can be disposed in that manner. When surface disposal is not a choice, beneficial use of recycled water becomes a favorable option. GRI compiled data to characterize the amount of water produced, production trends, and pertinent environmental regulations and analyzed localized produced water management strategies and costs. Annual oil, gas, and water production volumes were documented for key fields in each of the oil and gas basins in ten states. Producers reporting high volumes of water coupled with high hydrocarbon production were identified and interviewed to obtain specific information about their strategies for managing or disposing of produced water and the costs associated with those strategies. The data are contained in ten atlases, one for each of the following major gas-producing states: Wyoming, Colorado, Utah, New Mexico, Montana, Kansas, Oklahoma, Illinois, Michigan, and Louisiana. The research also produced a handbook that is a resource for gas producers and provides them with actual produced water management practices and disposal economics for 26 basins in ten states. The handbook also describes technologies that are used to treat or handle produced water. GRI published the atlases on a single compact disc in 2003. The Handbook is a separate GRI publication, also published in 2003.

Gas Resource and Production Potential of the Lewis Shale: The Lewis shale formation of the San Juan Basin in Colorado and New Mexico has an enormous gas-in-place volume. The properties of the reservoir and the mechanisms that control gas production from this formation are not well understood. GRI conducted formation evaluation research to quantify the gas-in-place volume stored by sorption, compression, and solution mechanisms; the depths of the most permeable rock; and the production mechanisms. The research collected and interpreted new data that were needed to improve the analysis of the wireline log data that are used to quantify the amount of gas in place and to determine the zones of greatest gas deliverability within the Lewis Shale. The research determined in situ gas permeabilities and estimated the amount of gas in place and how much of it should be recoverable. Shale gas reservoirs extend throughout the Western Cretaceous Basins from New Mexico to Canada. The amount of gas in place documented for the San Juan Basin are likely to be present in at least eight western basins. The formation evaluation approach implemented and documented during this research is applicable to all of these basins. The results of the research were published in a comprehensive report in 2003, GRI-03/0037, Final Report: "Lewis Shale Gas Resource and Production Potential". The information will help E&P companies understand this unconventional resource and will serve as a starting point for applying improved reservoir characterization technology to the development of the Lewis and other shale gas reservoirs. The enhanced understanding will lead to lower exploration costs and increased production of natural gas from shale formations.

* Enhancement to a previous product.

Appendix B
GRI RD&D Results That Have Been Placed in Commercial Use in 1999 Through 2003

RESIDENTIAL

1. Combo Systems Sizing and Installation Guidelines – 1992/2000
2. NAECA Water Heater Assessment - 2000
3. Indoor Emissions from Cooking – 2001
4. Summary Report of GRI's Venting Research - 2002
5. Gas Venting Safety Assessment - 2002
6. Accurate Assessment of Heat Pump Efficiency – 2002
7. Upgrades to the National Fuel Gas Code - 2003

COMMERCIAL

8. GATC Quick Response Activities – 1995/1999
   (Life-Cycle Cost Model for Food Service Technologies)
9. BinMaker™ Pro: The Weather Summary Tool – 1997/2000
10. kitchenCOST™ Software- 1998/99
11. Modulating Indirect-Fired Make-Up Air Unit - 1999
12. GATC: AERCO Benchmark Boiler - 1999
13. Engine Rooftop Heat Pump (Goettl 15-20 ton) - 1999
14. PITCO Gas Fryers - 1999
15. AUTOFRY™ Deep Fat Fryer - 1999
16. Analysis of Commercial Sizing and Installation Guidelines - 2000
17. Gas Cooling Guide – Pro Version - 2000
18. York 600 RT 134a Chiller - 2000
19. Tecogen 150 RT 134a Chiller - 2000
20. Trane Single Effect Horizon Chiller - 2000
21. Chiller Application Briefs - 2000
22. Restaurant Kiosk Ventilation and High-Performance Gas Countertop – 2000
23. Comparison of Radiant and Convective Unit Heaters - 2002
24. Gas-Fired Commercial Steam Cooker – 2002
25. Building Energy Analyzer™ - 2003

INDUSTRIAL

26. Process Application of Composite Radiant Tubes (and Case Studies) and Advanced U-Shaped Radiant Tubes - 1994/99/2002
27. Low-NO_x Air Staging for Glass Melting/Low-NO_x Combustion System for Glass Furnaces 1995/2003
28. Industrial Boiler Gas Cofiring (including Biomass) - 1995/99
29. High Performance Infrared Burners (and Application Tools) – 1995/99
30. METHANE de-NOX® Controls for Stoker Boilers - 1999
31. Ultra-Low-NO_x Burner for Boiler Retrofit - 1999
32. Forced Convection Heater (FCH) Systems – Automotive – 2000
33. Oscillating Combustion Burner - 2001

34. Radiant Heater Characterization Facility - 2001
35. Low-NO_x Retrofit Burners for Fire-Tube Boilers – 2002
36. Low-Cost Multi-Gas Continuous Emissions Monitor – 2002
37. Low-NO_x, High-Heat-Transfer Burner 2003
38. LNG Interchangeability in Burners - 2003

POWER GENERATION

39. DGen Pro™ Software – 1998/99/2000
40. SOAPP™ Modules – 1998/99
41. Microturbines (Capstone and Honeywell) - 1999
42. Distributed Generation Guidebook for Municipal Utilities - 1999
43. IR PowerWorks Microturbine Cogeneration Systems – 2000
44. Advanced High-Output Gas Engine-Generator (Caterpillar 3500® Series) – 2001
45. Distributed Generation Switchgear – 2003
46. Guidebook to Gas-Fired Distributed Energy Technologies - 2003

TRANSPORTATION

47. Cummins C8.3G Engine – 1996/2001
48. John Deere 8.1L Engine – 1996/99/2002
49. MACK E7G Refuse Hauler – 1996/2002
50. John Deere 6.8L – 1998/99
51. NGV Cylinders (Types 1 and 2) - 1999
52. Glass-Fiber-Wrapped Fuel Tanks for NGVs - 2000
53. Advanced NGV Fueling Dispenser
54. Best Practices for Medium-and Heavy-Duty NGV Fuel System Design - 2002
55. Clean Cities Initiative to Evaluate NGV Technology - 2002
56. Resource Guide for Heavy-Duty LNG Vehicles - 2002
57. Regional Natural Gas Vehicle Fueling Infrastructure Standards - 2002

DISTRIBUTION

58. PE LIFESPAN FORECASTING™ – 1994/2001
59. Plastic Pipe Across Bridges – 1995/99
60. DrillPath™ Guided Boring Software – 1996/99
61. Pipe Splitting Tool - 1998/02
62. TUBIS™ Software for Repair/Replace Decisions - 1999
63. Pipe Ovality and Scratch Depth Measurement Device and Guidelines - 1999
64. Plastic Pipe Repair Techniques - 1999
65. Starline® 2000 Renewal Technology - 1999
66. Guided Mole - 1999
67. Gas Holder Manual of Practice - 1999
68. Precision Pipe Locator - 2000
69. One-Step Paving - 2000
70. Bare Steel Maintenance Optimization System (BASMOS) Software - 2000
71. Soil Compaction Supervisor - 2000

72. Self-Loading, High-Efficiency Trailer for Coiled PE Pipe - 2001
73. Cold-Mix Restoration of Pavement Cuts - 2001
74. Imaging Underground Utility Structures - 2001
75. Comparative Evaluation of PE Pipe Materials - 2001
76. Directional Drilling for Plastic Pipe under Railroad Crossings - 2001
77. Gas Distribution Cost Database - 2002
78. Effect of Bomb Blasts on Gas Distribution Equipment- 2002
79. Assessment of PVC Pipe - 2002
80. Effect of Utility Cuts on Pavement Quality - 2002
81. Plastic Pipe Informational Web Site - 2002
82. Evaluation of the Performance of Carbon Monoxide Alarms - 2002
83. Worker Exposure to Hazardous Substances – 2002
84. Safety of Vacuum Excavation Operations - 2003
85. Gas Distribution Construction Guide - 2003
86. Removing Cyanide Wastes from MGP Sites – 2003
87. Chemical Fingerprinting for Enhanced Environmental Forensic Analysis - 2003

PIPELINE

88. Clock Spring® Composite Pipeline Repair Material – 1995/99
89. Risk Assessment/Risk Management Guidelines – 1996/99
90. Breeze Haz™ Environment and Safety Offsite Consequence Modeling Software - 1999
91. Emeritus Report B31.8 Code, Federal Pipeline Safety Regulations - 2000
92. Elastic Wave Vehicle Tool - 2000
93. Gas Leak Measurement Device (Hi-Flow® Sampler) – 2000/03
94. API 14.1 Gas Sampling Standard - 2001
95. Ultrasonic Meter Installation Effects -2001
96. Orifice Meter Operational Effects - 2001
97. Orifice Plate Installation Effects - 2001
98. Gas Storage Well Rehabilitation and Damage Prevention - DamageExpert™ Software -2001
99. Satellite Radar Interferometry Measurement of Slope Movement - 2001
100. AIRCalc™ Software – 2001
101. Predicting the Integrity of Storage Caverns in Thin Salt Beds - 2002
102. ASME Standard for Pipeline Integrity Management - 2002
103. NACE Standard for Direct Assessment of Pipeline Corrosion - 2002
104. Revegetation of Rights-of-Way in Wetlands - 2002
105. Reference Manuals of Best Practices for Horizontal Directional Drilling and its Effects in Wetlands - 2002
106. Best Environmental Practices for Pipeline Construction - 2002
107. Integrated Vegetation Management – 2002
108. Environmental Effects of Pipeline Crossings of Streams - 2003
109. Standard for Coriolis Meters - 2003

EXPLORATION AND PRODUCTION

110. Glycol Dehydrator Emissions Calculation Program – GLYCalc™ - 1992/2000
111. Gas Composition Database – 1996/2001
112. Unconventional Natural Gas Database – 1999/2001

113.Nitrogen Removal Requirements Report - 1999
114.Downhole Gas/Water Separation CD-ROM - 1999
115.Advanced Crosswell Seismic Source - 1999
116.High Power VSP Mechanical Seismic Source - 1999
117.Advanced Stimulation Technologies CD-ROM - 1999
118.Coiled Tubing Standards - 1999
119.GRI–MSTR™ Software and Report to Predict Toxicity of Produced Water Discharged to the Marine Environment – 1999
120.ProTreat™ Software for Amine Gas Treating Applications - 2000
121.Cased Hole Resistivity Tool - 2000
122.Cased Hole Pressure Tool - 2000
123.Well Siting in Carbonates – EGI Report - 2000
124.Portfolio of Emerging Natural Gas Resources – Rocky Mountain Basins - 2000
125.Mercury Contamination Training Workshop – 2000
126.New Gas Exploration Concepts - 2001
127.StreamAnalyzer™ Software - 2001
128.Enhanced Seismic Spectral Processor - 2002
129.Evaluating Ecological Impacts at E&P Sites – 2002
130.Cement Pulsation Technology - 2003
131.Analysis for Radium in Marine Sediments - 2003
132.Produced Water Atlases and Handbook - 2003
133.Gas Resource and Production Potential of the Lewis Shales - 2003

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Authority to Increase Rates for its Gas Distribution Service	)	Case No. 07-829-GA-AIR
In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Approval of an Alternative Rate Plan for its Gas Distribution Service	)	Case No. 07-830-GA-ALT
In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Approval to Change Accounting Methods	)	Case No. 07-831-GA-AAM

DIRECT TESTIMONY OF
DANIEL M. IVES
ON BEHALF OF
DOMINION EAST OHIO

___ Management policies, practice and organization

_X_ Operating income

_X_ Rate base

___ Allocations

___ Rate of return

___ Rates and tariffs

___ Other

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ATTACHMENT DMI-8.1

ATTACHMENT DMI-8.2

ATTACHMENT DMI-8.3

ATTACHMENT DMI-8.4

APPENDIX A

Direct Testimony of

Daniel M. Ives

I. IDENTIFICATION AND QUALIFICATIONS

Q1. Please state your name, occupation, and business address.

A1. My name is Daniel M. Ives. I am a Managing Director of Lukens Energy Group ("Lukens"), a unit of Black & Veatch Corporation ("B&V"), under retention by the East Ohio Gas Company d/b/a Dominion East Ohio ("DEO" or "Company"). My business address is 5151 San Felipe, Suite 1900, Houston, Texas 77056.

Q2. What is your background and experience in the gas industry?

A2. I have been employed as a consultant with Lukens, an energy consulting firm, since January 1999. In January 2005, Lukens became a unit of B&V. Prior to joining Lukens, I was employed by several natural gas transmission and distribution companies, including: ANR Pipeline Company, Detroit, Michigan, as Vice President-Rates and Regulatory Affairs from 1995-1998; Algonquin Gas Transmission Company, Boston, Massachusetts, as General Manager-Rates and Billing from 1992-1995; and Washington Gas Light Company, Washington, DC, as Director of Maryland Rates and Regulatory Affairs from 1985-1992, and as Director of Federal Regulation from 1982-1985. From 1976-1982, I held various management positions in non-utility operations, auditing and accounting at Washington Gas, including three years as Secretary and Treasurer of four of its non-utility subsidiaries.

Q3. What are your educational and professional qualifications?

A3. In 1970, I received a B.A. and, in 1975, a B.S. from the University of Maryland. In 1979, I became a Certified Public Accountant in the State of Maryland, where I maintain an inactive status. I am a member of the American Institute of Certified Public Accountants and I am a member, and Past Chair, of the American Gas Association's Rate and Strategic Issues Committee.

I have filed testimony with the Public Service Commissions of Georgia, Kentucky, Maryland, New York, South Carolina and West Virginia; the Illinois Commerce Commission; the Oklahoma Corporation Commission; the Pennsylvania Public Utility Commission; the Texas Railroad Commission; the Virginia State Corporation Commission; and the Federal Energy Regulatory Commission ("FERC"). This testimony has covered such topics as pension expense, cost of service, purchased gas costs, cost allocation, rate and tariff design, oil pipeline rates, and regulatory policy. I have also testified before the joint Alaska Legislative Budget and Audit Committee and the Senate Resources Committee on the natural gas pipeline certificate process. Additionally, I have published an article in *Public Utility Fortnightly* on the ratemaking treatment of pension credits. My Curriculum Vitae is attached to my direct testimony as Appendix A.

II. IDENTIFICATION OF EXHIBITS

Q4. What exhibits and appendices do you sponsor in this proceeding?

A4. I am sponsoring the following exhibits and appendices, all of which were prepared by me or under my direction and supervision:

• DEO Exhibit 8.0	Direct Testimony
• Attachment DMI-8.1	DEO's FAS No. 87 Pension Expense
• Attachment DMI-8.2	DEO's FAS No. 158 Pension Asset
• Attachment DMI-8.3	Dominion Resource's Pension Plans' Performance

- Attachment DMI-8.4 — DEO's Return on Plan Assets Sensitivity
- Appendix A — Curriculum Vitae of Daniel M. Ives

III. PURPOSE OF TESTIMONY

Q5. What is the purpose of your testimony in this proceeding?

A5. My testimony describes and supports DEO's proposed regulatory treatment of its test period pension expense credit ("negative pension expense"), the related accumulated deferred income taxes, and its pension asset. Specifically, I discuss the following:

- DEO's pension expense credit and the related pension asset and accumulated deferred income taxes;
- DEO's accounting for pension expense and its pension plans' funded status under Financial Accounting Standards 87 and 158;
- ERISA limitations on the withdrawal of funds from pension plans;
- DEO's proposal to (1) exclude the test period pension expense credit from its cost of service as set forth in Schedule C-3.26, (2) exclude its test period pension asset from rate base, and (3) exclude the related accumulated deferred income taxes from rate base;
    - In conjunction with this topic, I will discuss the regulatory precedent for exclusion of the pension expense credit from cost of service and exclusion of the related accumulated deferred income taxes from rate base;
    - I will also discuss how exclusion of the pension asset from rate base is symmetrical with DEO's exclusion of its pension expense credit from the cost of service, along with the regulatory precedent for exclusion of the pension asset;
- The propriety and benefits of DEO's proposed ratemaking adjustments to its stakeholders (ratepayers, regulatory process participants, employees, and shareholders):
    - In conjunction with this topic, I will explain how DEO's pension asset is resultant from the superior performance of the Company's pension plan and the Company's labor cost management, not from ratepayer contributions;

– I conclude by recommending that the Commission adopt DEO's proposed ratemaking adjustments.

Organizationally, my testimony will generally follow the order of the topics listed above.

IV. DEO'S PENSION ASSET, PENSION EXPENSE, ACCUMULATED DEFERRED INCOME TAXES, AND FUNDED STATUS OF THE PLANS

Q6. Please identify and describe DEO's pension plans.

A6. DEO has three pension plans that cover its union employees; the East Ohio Gas plan, the River Gas Division plan and the West Ohio Gas Division plan. Non-union employees are covered by the plan of DEO's parent company, Dominion Resources, Inc. ("DRI"), and the related expense and asset are allocated to DEO. DEO's pension asset as of December 31, 2006, was \$615.0 million and its 2006 pension expense was \$49.4 million, as summarized below:

DEO Plans	Pension Asset 12/31/06	2006 Pension Expense
DEO Union Plans	\$420.0 million[1]	(\$31.3 million)[2]
DEO Mgmt. Plan	\$195.0 million	(\$18.1 million)
Total	\$615.0 million	(\$49.4 million)

Q7. Does DEO have any accumulated deferred income taxes related to its pension expense credits?

A7. Yes. DEO has \$215.0 million of accumulated deferred income taxes on its books related to its long history of pension expense credits.

[1] See Attachment DMI-8.2 for calculation.

[2] See Attachment DMI-8.1 for calculation.

Q8. Are DEO's pension plans fully funded?

A8. Yes. DEO's pension plans for union employees and its management plan are all *more than fully funded* and, overall, the Company has a surplus—a pension asset of $615 million, which has grown markedly from the $24.9 million pension asset in DEO's last rate case in 1994.

It is important to note that the growth in the plans' funded status is *not* due to ratepayer contributions, because there have not been any ratepayer contributions since 1994. Rather, the growth in the pension asset is due to the favorable performance of the pension plans' investments coupled with the Company's ongoing labor cost management efforts.[3]

Q9. Did ratepayers overpay for pension costs prior to DEO's last rate case?

A9. No. To the extent that pension-related costs were an expense rather than a credit prior to DEO's last rate case, the test year expenses would have been based on actuarial estimates of those costs at the time of the proceeding. The fact that DEO had a pension asset of less than $25 million as of December 31, 1993 (the date certain in its last rate case), suggests that the actuarial accruals for pension expense were generally in line with the projected obligations of the pension plan prior to that point in time.

Q10. Did DEO make any cash contributions to its pension plans in 2006?

A10. No. DEO has not made cash contributions to its pension plans since 1992 because, as noted before, they are fully funded.

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[3] See Attachment DMI-8.3 for overall performance of DEO's pension fund.

Q11. Have DEO's ratepayers been funding the pension plans through DEO's rates?

A11. No. The pension expense reflected in the filed cost of service in DEO's last rate case, in 1994, was a $6.2 million *credit*.[4] Company personnel inform me that the 1994 case was settled along the general lines of the Staff Report of Investigation issued in the case, which did not propose any adjustments to that component of the cost of service. Thus, because DEO's filed pension expense was a credit, it follows that the Company's ratepayers have *not* been funding the Company's pension plans through the rates that they have been paying since at least 1994. Instead of funding DEO's pension plan, customers have in theory received a cumulative credit—a windfall—of $77.5 million over the approximately twelve and a half years since DEO's current base rates were established.

Q12. Was the substantial growth in the Company's pension asset attributable to ratepayer funding?

A12. No. None of the $590 million increase in the pension asset, from $24.9 million to $615 million, since that last rate case can be attributed to ratepayer funding because, as indicated in the prior response, there was no pension-related cost—and hence no contribution to the pension asset—reflected in customers' rates.

Q13. Why has DEO focused on the pension expense issue in this case, when it did not do so in its prior case?

A13. The answer is simple. In contrast to the 1994 credit of $6.2 million, DEO's pension expense credit has grown to $49.4 million in 2006 and is projected to be $47.7 million for the test year. This level of credit would result in a significantly larger reduction to DEO's cost of service if it were included in setting rates. Thus, as discussed further

[4] Further, DEO reflected a $24.9 million pension asset on its books as of December 31, 1993.

herein, the working capital impact of the negative pension expense in this case is *substantially* greater than in DEO's last rate case. As a percentage of the total revenue increase requested, the 1994 credit constituted only 5% of the calculated revenue deficiency, whereas the test year credit in this case amounts to 64% of the revenue deficiency.

Q14. What would be the working capital impact of reducing the revenue requirement by the amount of the pension expense credit?

A14. Reducing the cost of service revenue requirement for the pension expense credit would require an increased working capital allowance that would generate at least $47.7 million of annual revenues, because the Company would have to source those funds from other than the cost of service, *i.e.*, by borrowing the funds, utilizing shareholder funds, or both.

V. DEO'S ACCOUNTING FOR PENSION EXPENSE AND PENSION ASSETS

Q15. How does DEO account for pension expense?

A15. DEO follows Financial Accounting Standard Board Statement No. 87 ("FAS 87"), "Employers' Accounting for Pensions" for its book accounting of pension expense. FAS 87 sets forth the manner in which DEO recognizes pension cost for book accounting purposes and the recognition of pension assets and obligations on its balance sheet, as recently modified by FAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." The pension cost elements identified in FAS 87 include:

- Service cost of today's employees;
- Interest cost associated with the projected benefit obligation;
- Actual return on plan assets;
- Amortization of unrecognized net gains or losses;

- Gains and losses associated with changes in projected benefit obligation or from experience different than projected;
- Amortization of unrecognized prior service cost; and
- Transition obligations at the date of implementation of FAS 87, in 1986.

Q16. How does FAS 158 affect pension accounting and reporting?

A16. FAS 158 does not modify the accounting for periodic pension expense as set forth in FAS 87; rather, it requires balance sheet reporting of the funded status of the plan, which is measured as the difference between the fair value of the plan's assets and the projected benefit obligation. Under FAS 158, companies with single-employer pension plans no longer report "prepaid pension cost" on their balance sheets, which amounts resulted primarily from funding in excess of recognized expenses.[5] Additionally, under FAS 158 companies may not net pension assets resulting from over-funded plans with pension liabilities resulting from under-funded plans; rather, assets from over-funded plans may be aggregated and liabilities from under-funded plans may be aggregated, but these assets and liabilities must be shown separately on the balance sheet. Thus, the funded status of the plans is moved from the financial statement notes to the balance sheet and these assets and liabilities are separately disclosed, resulting in greater transparency of the firm's assets and obligations.

Q17. How are future pension benefit costs estimated?

A17. The estimation of future benefit costs is developed through an annual actuarial process of updating assumptions for changes in key variables such as the number of eligible

[5] Note that FAS 158 only applies to single-employer pension plans. The DEO Management Plan represents DEO's participation along with several other companies in the Dominion Salaried Pension Plan and is treated for accounting purposes as a multi-employer plan. Therefore, the DEO Management Plan is not accounted-for in accordance with FAS 158 and the asset for this plan represents funding in excess of recognized expenses, rather than the fair value of plan assets in excess of the projected benefit obligation.

employees, employee ages, and mortality rates; the benefit obligation discount rate; and investment performance of the plan assets in fixed income assets, equities, and other investments. Thus, under FAS 87 accounting, DEO's financial statements reflect the attribution of pension costs to the period in which employee service is rendered rather than the cash payments made by DEO into its pension plans.

DEO utilizes the independent actuarial consulting firm of Watson Wyatt Worldwide to provide an annual actuarial valuation and to document the funded status of the plans.

Q18. Please explain DEO's pension expense credit.

A18. In 2006, DEO recorded a pension expense credit, under FAS No. 87 book accounting, of \$49.4 million. This pension expense credit is primarily due to the following factors: (1) earned returns on plan assets greater than expected returns; and (2) a reduction in service cost for current employees.

Q19. Has DEO's pension expense been negative for some period of time?

A19. Yes. DEO's pension expense has been negative every year since its last rate case in 1994. In its 1994 rate filing, DEO's test year pension expense credit was \$6.2 million and, in 2006, it was \$49.4 million.

VI. ERISA LIMITATIONS ON FUND WITHDRAWALS AND THE IMPACT ON COST OF SERVICE

Q20. Are DEO's pension assets held in trust?

A20. Yes. Under federal pension law, DEO's pension assets are held in trust for the benefit of employees. Under the Employee Retirement Income Security Act ("ERISA"), the assets of the plan cannot inure to the benefit of the employer, except for: (1) certain corrections of errors; (2) conditional contributions pursuant to initial plan qualification or pursuant to tax deductibility qualification; or (3) termination of the plan pursuant to section 1344 of the ERISA code.[6]

Section 1103, Title 29, United States Code provides, in part:

"Assets of plan not to inure to benefit of employer; allowable purposes of holding plan assets

(1) Except as provided in paragraph (2), (3), or (4) or subsection (d) of this section, or under sections 1342 and 1344 of this title (relating to termination of insured plans), or under section 420 of title 26 (as in effect on October 22, 2004), *the assets of a plan shall never inure to the benefit of any employer and shall be held for the exclusive purposes of providing benefits to participants in the plan and their beneficiaries and defraying reasonable expenses of administering the plan."* (Emphasis added.)

Q21. Based on your understanding of Section 1344 of the ERISA code, may DEO withdraw funds from its pension plan?

A21. No. As noted above, pension assets shall not inure to the benefit of employers or, by extension, customers of employers. Pension expense can be viewed as a one-way street: a company can only pay into its plan, and money can only flow out to the intended recipients: the employees. Thus, pension expense credits booked by DEO do not represent a source of cash for the Company.

[6] See Section 1103, Title 29 US Code.

Q22. What would be the effect of including the Company's pension expense credit in its ratemaking cost of service?

A22. Because, by law, cash cannot be withdrawn from the pension plan, inclusion of the negative pension expense in DEO's revenue requirement is tantamount to requiring that the Company collect less cash in its rates than is necessary to cover its cash cost of service, and such a situation is essentially confiscatory.

Q23. Is there a ratemaking remedy for the treatment of negative pension expense?

A23. Yes. In order to preclude DEO's collection of less than its full cash cost of service, it is appropriate to adjust DEO's negative pension expense to zero for ratemaking purposes and remove the pension asset and associated accumulated deferred income taxes from DEO's rate base. I discuss this proposed treatment in more detail below.

VII. DOMINION'S PROPOSED PENSION-RELATED ADJUSTMENTS

Q24. Please explain DEO's proposed test period pension-related adjustments.

A24. DEO proposes to: (1) adjust its cost of service to exclude its $47.7 million test year pension expense credit; and (2) adjust its rate base to exclude the pension asset and pension-related related accumulated deferred income taxes.

The adjustments are proposed so that DEO will recover in rates the cash it needs to operate its business. If DEO does not set its test period pension expense credit to zero or receive appropriate working capital treatment of the credit, it will fail to collect in rates all of the cash required to operate its business. This is because flow-through to ratepayers of the pension expense credit in the cost of service, with no offsetting source of cash funds, would result in DEO under-collecting its cash operating expenses. As previously discussed, under ERISA pension law, DEO cannot withdraw funds from its pension plan to fund the pension credit flow-though to ratepayers.

No prudent business would intentionally or willingly price its product so as to continually under-collect its cash operating costs. Thus, DEO proposes in this case that the Commission allow it to collect in rates its cash operating costs by exclusion of the pension expense credit from its cost of service, setting it to zero for ratemaking purposes, along with elimination of the pension asset and pension-related accumulated deferred income taxes from the rate base computation.

Q25. Why is it appropriate to set the pension-related accumulated deferred income taxes to zero, as well as the pension expense credit?

A25. It is appropriate to set the pension-related accumulated deferred income taxes to zero for ratemaking purposes as a matter of symmetry: since the pension expense credits have been eliminated by setting the expense to zero, the related income tax effect of those credits should also be eliminated by setting the pension-related accumulated deferred income tax amount to zero, thus removing it as a component of, and a reduction to, the test period rate base.

Q26. Why is DEO also proposing to exclude its pension asset from rate base for ratemaking purposes?

A26. Exclusion of the pension asset from rate base is consistent with setting the negative pension expense to zero and removing the related accumulated deferred income taxes from rate base.

All of the Company's proposed adjustments will keep the company whole on a cash basis because: (1) the expense will be set to zero, allowing the company to recover in rates its cash expenses; (2) the pension asset's growth was primarily due to favorable returns on investment and the Company's labor cost management efforts, not due to the ratepayer funding of the pension plan; and (3) by exclusion of the pension asset and pension-related accumulated deferred income taxes from date certain rate base, the Company's return will be consistent with its test year operating income.

Further, the adjustments are appropriate because the occurrence of a pension expense credit is not just a one-time event. The pension expense credit is likely to continue to occur, particularly in light of the plan assets' continued favorable performance and DEO's reduced service cost obligations.

Q27. Do DEO's stakeholders benefit from DEO's proposed pension adjustments?

A27. Yes. DEO's ratepayers, regulatory process participants, employees, and shareholders all benefit from DEO's proposed ratemaking pension treatment.

Q28. How do those various stakeholders benefit from DEO's proposal?

A28. Ratepayers benefit because they will not have to contribute to the pension-related costs of DEO's employees until such time as there is an actual cash contribution required. There is no year among the Company's most recent five-year forecast where a cash payment to the pension trust will be necessary. As a result, the Company's proposed treatment will result in more stable rates. The resulting price certainty is increasingly important given the expectation of continued natural gas commodity pricing volatility. Those involved in the regulatory process will benefit from a much more straightforward approach to the treatment of pension expense in future DEO rate cases, without the need to review actuarial studies and assess different test year values from one case to the next even though there is no change in the cash contribution (or lack thereof) to the pension trust. Absent adjustments that offset the inclusion of the pension expense credit in the cost of service and the associated accumulated deferred income tax in rate base, DEO may be required to seek continual rate relief, consuming substantial time and dollars for all of the parties and possibly resulting in continued rate increases for customers.

In effect, DEO's proposal establishes the just and reasonable expense for this item utilizing a cash basis consistent with the unique ERISA laws surrounding access to the pension trust.[7] By setting the negative pension expense to zero and removing the associated accumulated deferred income taxes and the pension asset from rate base for ratemaking purposes, the Commission will provide DEO the cash it needs to operate its facilities and pay its employees. Employees and shareholders benefit from DEO's proposal because the Company will be allowed to recover in rates the cash necessary to fund its operations and support capital expenditures. Commission support of a financially stable company will also allow DEO to attract and to retain the quality workforce that its ratepayers want and deserve.

Q29. Please discuss the interest and market sensitivity of DEO's pension earnings.

A29. It should be noted that DEO's pension expense credit is subject to substantial change. A 25 basis point decrease in the expected return on plan assets would reduce DEO's FAS

[7] DEO's other post-employment benefits ("OPEBs") for retiree medical expenses are funded through a VEBA trust. The annual cash funding of the VEBA is based on the accrual of the expense. Hence, DEO's accrual and cash basis for OPEBs are virtually identical. DEO informs me that it is willing to expressly adopt cash basis rate treatment for those retiree benefits as well.

87 pension credit of ($47.7 million) by $ 1.65 million, and a 100 basis point decrease would result in a $6.6 million reduction.[8]

Q30. What is the implication of this interest rate and market sensitivity?

A30. Stock market fluctuations, such as those recently experienced in July and August 2007, and interest rate changes could result in a pronounced impact on DEO's pension expense. Flowing through a large pension credit, $47.7 million, in the cost of service could be well in excess of future actual pension expense experience, particularly should the stock market undergo a substantial and prolonged downturn. Under DEO's proposal to set pension expense to zero for ratemaking purposes, the Company and ratepayers would be insulated from the impact of such volatility and the possible turn of DEO's pension expense from negative to positive, unless or until the Company files a rate case.

VIII. REGULATORY PRECEDENT FOR DEO'S PROPOSED PENSION ADJUSTMENT

Q31. Please discuss the regulatory precedents for ratemaking treatment of negative pension expense.

A31. There are numerous cases in which a regulatory agency has addressed the elimination of pension expense credits from a utility's cost of service for ratemaking purposes. Consider the following cases:

In FERC Docket No. RP87-30-000, Colorado Interstate Gas Company ("CIG") argued that because it could not realize any of the market gain of its pension plan without termination of the plan, it should not be required to flow through a negative pension expense in its cost of service. A CIG witness stated, in testimony the Administrative Law

[8] See Attachment DMI-8.4.

Judge described as persuasive, "The actual dollars associated with the excess of market value over pension obligations is simply not accessible to CIG without terminating the plan...." Based on this testimony, the ALJ concluded, "Since there is no access [to the plan assets] the deduction should not be made."[9]

In an opinion issued December 22, 1988, the Michigan Public Service Commission ("Michigan PSC") upheld Michigan Consolidated Gas Company's ("MichCon") ratemaking adjustment setting pension expense to zero, while PSC Staff urged adoption of a pension expense credit of $666,000. MichCon's witness "calculated MichCon's pension expense under SFAS 87, which resulted in a negative expense due to the then-existing plan assets and expected return. He proposed setting pension expense at zero because use of a negative expense would, in effect, require the company to refund prior pension costs to ratepayers and the company could not withdraw funds from the plan's trust to compensate the company for this refunding." The Michigan PSC noted that "use of a negative pension expense for ratemaking purposes will require the company to refund previous pension costs and that the company cannot remove funds from the pension trust." The Michigan PSC therefore concluded that "pension expense should be set at zero for this rate case."[10] In making this decision, the Michigan PSC recognized that FAS 87 was "a recent development" and that its treatment in that case was subject to change if experience dictated. Experience, however, has not dictated such a change, as demonstrated by the similar treatment of MichCon's pension expense in 2005 (see below).

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[9] 43 FERC P63, 001; 1988 FERC LEXIS 822.

[10] Opinion, 1988 Mich. PSC LEXIS 393; 98 P.U.R.4th 273.

In a December 13, 1990 Order, the Pennsylvania Public Utility Commission ("Pennsylvania PUC") held that West Penn Power should not be required to flow-through a non-cash pension credit to ratepayers, finding that "pension expense should be treated on a 'cash only' basis."[11] West Penn's pension plan, like DEO's plan, was over-funded at the time. The company sought a positive pension expense, and the ALJ recommended a negative pension expense, with each side relying on projections and not on actual cash expenditures or revenues. The Pennsylvania PUC rejected both approaches, looking instead to the cash effect for ratemaking purposes.

In a 1995 proceeding involving NYNEX, the Massachusetts Department of Telecommunications and Energy ("MDT&E") held that "test year tax-deductible cash pension contributions that are demonstrated to be annually recurring may be included in rates." Further, the MDT&E held that because the company did not make a cash contribution for pension funding in the test year it would disallow the negative pension expense of $21.4 million computed under FAS 87, noting that "[t]his results in a corresponding increase to total expenses."[12]

At the Texas Railroad Commission in 2000, in Docket GUD No. 9002-9135, Energas Company sought to set its pension expense credit of ($1,102,111) to zero for ratemaking purposes. In their Proposal for Decision the hearing examiners found that "the appropriate means of treating this negative pension expense is to set it at zero for ratemaking purposes," stating that "The Commission should not attempt to compensate

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[11] 1990 Pa. PUC LEXIS 142; 73 Pa. PUC 454; 119 P. U. R. 4th 110, page 113.

[12] Massachusetts Department of Telecommunications and Energy, D.P.U. 94-50, Order dated May 12, 1995, page 191, 1995 Mass. PUC LEXIS 1.

ratepayers for past payments that were allowed in previous Commission Orders, because it could result in retroactive ratemaking."[13] The case ultimately was resolved on stipulation.

In a 2004 Pacific Bell ("PacBell") case, the California Public Utilities Commission ("CPUC") stated that "[i]t is not in the public interest to treat pension earnings as utility profits and to require distribution of pension earnings to ratepayers."[14] On this point the CPUC stated:

> The argument that booking a negative ACM [pension] amount as a corporate profit and requiring sharing with ratepayers will have no effect on pensions lacks credibility. In particular, it is Pacific's revenues that will supply the resources for sharing. Thus, booking a negative ACM [pension] amount as a corporate profit and requiring sharing turns a pension asset into a potential liability because paper gains in pension assets will produce real liabilities—funds owed to ratepayers.[15]

Further, the CPUC ruled that "[t]reating pension earnings as utility profits creates incentives to manage pension funds to reduce utility liabilities, thereby undermining the fiduciary responsibilities of pension fund managers."[16] The CPUC also found that under federal pension law PacBell did not have access to its pension fund assets and could not distribute such funds to ratepayers. Further, the CPUC accepted PacBell's proposal to set its negative pension expense to zero for ratemaking purposes.

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[13] Texas Railroad Commission, Docket GUD No. 9002-9135, Proposal for Decision issued November 2, 2000, page 75.

[14] CPUC Decision 04-02-063; Rulemaking 01-09-001; Investigation 01-09-002; 2004 Cal. PUC LEXIS 55, Ordering Paragraph 8.

[15] CPUC Decision 04-02-063; Rulemaking 01-09-001; Investigation 01-09-002; 2004 Cal. PUC LEXIS 55, paragraph 3, Discussion.

[16] CPUC Decision 04-02-063; Rulemaking 01-09-001; Investigation 01-09-002; 2004 Cal. PUC LEXIS 55, Ordering Paragraph 6.

In a 2005 Michigan Consolidated Gas Company ("MichCon") case, the Michigan PSC approved a PSC Staff and MichCon plan to reduce MichCon's pre-paid pension expense to zero. The Commission stated:

> The pre-paid pension expense asset represents a non-interest producing utility asset comprising the cumulative negative pension expenses that the company has encountered. The Staff's and Mich Con's position provides an approximation of a reasonable level of that asset, which must be accounted for as part of the test-year working-capital calculation. The pre-paid pension expense asset exists, it is appropriate, and it should be included within the working capital calculation. And, under the Staff's proposal, that asset will not continue to grow.
>
> As regards utilization of a zero level for an appropriate O&M pension expense for the test year, the Commission finds the Staff's and Mich Con's proposal reasonable and appropriate. Setting the O&M pension expense level at zero for ratemaking purposes will provide MichCon necessary and reasonable cash flow, it will stop the continued growth of the pre-paid pension expense asset, and the accounting for negative pension expense requested by MichCon will prevent further growth in the working capital requirement, thus providing benefits to future ratepayers.[17]

Thus, MichCon sought and was granted both cost of service exclusion of the pension credit, setting it to zero, and rate base inclusion of its pension asset. In exchange for such treatment, MichCon and Staff agreed to establish a regulatory liability for any future negative pension costs, effectively capping the amount of the prepaid pension asset included in working capital.

In contrast to MichCon's regulatory treatment, DEO is not seeking *both* cost of service exclusion of the negative pension expense and rate base inclusion of the pension asset. Rather, DEO is seeking exclusion of the negative expense from cost of service, along with related accumulated deferred income taxes, and exclusion of the pension asset from

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[17] Opinion and Order Granting Rate Relief, Michigan Public Case No. U-13898 and Case No. U-13899, April 28, 2005, page 32.

rate base, which treatment DEO believes will provide it the appropriate level of funds necessary to run its business.

Based on the above cases, it can be seen that the FERC and several state regulatory commissions have recognized that pension funds should not be used for rate reduction purposes and that rate reductions to adjust for prior pension payments may constitute retroactive ratemaking. DEO's proposed adjustments to set its ratemaking pension expense credit to zero and to remove the associated accumulated deferred income taxes from rate base is consistent with the regulatory treatment afforded other companies in the cited regulatory actions and will provide DEO the needed working capital to fund its cash operating expenses.

Q32. Is this the first time that DEO has brought the negative pension expense issue to the Commission's attention?

A32. No. As previously discussed, DEO had a negative pension expense of $6.2 million in its 1994 cost of service and rate filing.

Q33. Is there anything barring the Commission from setting the pension credit to zero, eliminating the associated pension-related deferred income taxes, and excluding the pension asset from rate base for ratemaking purposes?

A33. No. The Commission has considerable leeway in setting rates and, as previously discussed, many regulatory bodies have acknowledged that when faced with a negative pension expense, 'zeroing out' the pension expense and corresponding asset is the best course to follow.[18] Alternatively, the Commission could include a working capital adjustment to recognize the cash flow impact of including the credit in test year expenses.

[18] See, e.g. discussion herein regarding actions of the California Public Utilities Commission, Michigan PSC, the Texas Railroad Commission, and the Pennsylvania Public Utility Commission.

That would, of course, ultimately leave the revenue requirement at approximately the same level. While I am informed that DEO is financially indifferent as to the two alternatives, its proposed treatment has the advantage of simplicity and it has been adopted in multiple jurisdictions. Further, excluding the pension asset from rate base would be symmetrical with exclusion of the pension credit from DEO's cost of service.

Q34. Would the Commission be bound in future cases involving other companies to grant the ratemaking treatment requested by DEO in this proceeding?

A34. No. The Commission has the authority and the responsibility to consider each rate case independently, based on the totality of the facts presented.

Q35. Is it appropriate to reduce the revenue requirement by the amount of the pension credit?

A35. No. DEO's pension plans, and its test period pension expense credit, are not sources of cash, and thus it would not be appropriate to include the pension expense credit in DEO's cost of service, reducing the overall revenue requirement. While FAS 87 requires DEO to recognize pension income when the estimated return on the pension assets is greater than its service costs, interest cost and amortization, this income is not available to DEO as a source of cash to flow through to ratepayers. Because DEO has no legal authority to receive cash benefits from the pension plan, for its own benefit or for disposition to its ratepayers either in the form of rate reductions or refunds, any such confiscatory flow-through to ratepayers would have to come from shareholder or borrowed funds.

DEO has not proposed to flow-through to ratepayers its pension income. Rather, it has proposed to set its ratemaking pension expense to zero and, as a matter of consistency, remove the associated pension asset and the pension-related accumulated deferred income taxes from rate base. DEO's proposed adjustments are logical, bona fide ratemaking proposals that are not prohibited by law, and are in fact similar to adjustments approved by other regulatory commissions for other utility companies in similar circumstances. The Company's proposal, if adopted, will provide it the necessary working capital to fund its operations.

Q36. In the future, what amount of pension expense will DEO seek to include in its cost of service?

A36. DEO's proposal in this case effectively sets its cost of service pension expense on a cash basis. In the future, if DEO makes cash contributions to the plans, it would seek ratemaking cost of service recovery of such amounts. If it incurs negative pension expense, it would adjust its cost of service to remove the credit and the related deferred income taxes.

IX. SUMMARY AND CONCLUSION

Q37. Please summarize why DEO's proposed adjustment is reasonable and necessary, and should be adopted by the Commission.

A37. As I have discussed, DEO's proposals to: (1) set test period pension expense to zero; (2) remove pension-related accumulated deferred income taxes from rate base; and (3) exclude the pension asset from rate base are reasonable and symmetrical and are necessary for the following reasons:

(1) DEO's ratepayers will benefit from stable, low rates with ratemaking pension expense set to zero;

(2) DEO's ratepayers and employees will benefit from a financially stable company with rates that recover the Company's cash operating expenses and a fully funded pension plan;

(3) DEO's pension plan performance is interest rate and market sensitive and subject to variability; hence, annual flow-through of DEO's test period pension credit of $47.7 million could result in too large of a credit to cost of service in future periods;

(4) DEO cannot utilize its pension assets to fund rate reductions and DEO's shareholders should not be required to fund a windfall rate reduction premised on retroactive ratemaking; and

(5) There is substantial regulatory precedent for setting pension expense credits to zero and excluding the associated accumulated deferred income taxes from rate base for ratemaking purposes. If the Commission grants the requested relief, then DEO should, for purposes of symmetry, exclude the pension asset from rate base, which would result in lower rates to DEO's customers.

Q38. What is your recommendation to the Commission?

A38. For the reasons discussed in my testimony, I recommend that the Commission: (1) accept DEO's proposed $47.7 million adjustment to its cost of service to set its ratemaking pension expense to zero; and (2) accept DEO's proposed exclusion of the pension asset and related accumulated deferred income taxes as an offset to rate base.

Q39. Does this conclude your direct testimony?

A39. Yes, it does.

(2) DEO's ratepayers and employees will benefit from a financially stable company with rates that recover the Company's cash operating expenses and a fully funded pension plan;

(3) DEO's pension plan performance is interest rate and market sensitive and subject to variability; hence, annual flow-through of DEO's test period pension credit of $47.7 million could result in too large of a credit to cost of service in future periods;

(4) DEO cannot utilize its pension assets to fund rate reductions and DEO's shareholders should not be required to fund a windfall rate reduction premised on retroactive ratemaking; and

(5) There is substantial regulatory precedent for setting pension expense credits to zero and excluding the associated accumulated deferred income taxes from rate base for ratemaking purposes. If the Commission grants the requested relief, then DEO should, for purposes of symmetry, exclude the pension asset from rate base, which would result in lower rates to DEO's customers.

Q38. What is your recommendation to the Commission?

A38. For the reasons discussed in my testimony, I recommend that the Commission: (1) accept DEO's proposed $47.7 million adjustment to its cost of service to set its ratemaking pension expense to zero; and (2) accept DEO's proposed exclusion of the pension asset and related accumulated deferred income taxes as an offset to rate base.

Q39. Does this conclude your direct testimony?

A39. Yes, it does.

COI-1381214v3

Dominion East Ohio
SFAS No. 87 Pension Expense

	Union Pension Plans a/
Service Cost	$ 6,676,808
Interest Cost	15,180,342
Expected Return on Plan Assets	(53,342,219)
Amortization of:	
Transition Asset	(20,000)
Prior Service Cost	243,009
Gains	-
2006 Net Periodic Pension Cost	**$ (31,262,060)**

a/ Includes amounts applicable to East Ohio Gas, River Gas Division, and West Ohio Gas Division plans applicable to DEO's union employees. Amounts reflect both expensed and capitalized pension costs.

Source: Watson Wyatt Actuarial Valuations as of January 1, 2006, issued April 11, 2007 for Dominion Pension Plans, Table 1, page 8, and DEO.

Dominion East Ohio
FAS No. 158 Pension Asset

		Union Pension Plans
Fair Value of Plan Assets at December 31, 2006	a/	$ 693,478,559
Projected Benefit Obligation at December 31, 2006	a/	$ 273,432,459
Pension Asset/(Liability)		$ 420,046,100

a/ Includes amounts applicable to East Ohio Gas, River Gas Division, and West Ohio Gas Division plans applicable to DEO's union employees.

Source: Watson Wyatt Actuarial Valuations as of January 1, 2006, issued April 11, 2007 for Dominion Pension Plans, Table 1, page 7.

Attachment DMI-8.3

Dominion Resources Pension Fund
Investment Performance
As of December 31, 2006

	Market Value a/	Percent of Fund a/	Annualized Rates of Return: One Year	Three Years	Five Years	Ten Years
Total Fund b/	$ 5,008,130,439	100.0%	14.1%	12.6%	9.9%	10.3%
Types of Assets						
U.S. Equity Composite	$ 1,920,130,139	38.3%				
Large/Mid Value	$ 494,147,167	9.9%				
Large/Mid Growth	$ 501,657,934	10.0%				
Large/Mid Core	$ 701,922,055	14.0%				
Small Value	$ 168,888,572	3.4%				
Small Growth	$ 53,514,410	1.1%				
International Equity	$ 658,518,492	13.1%				
Real Estate	$ 384,027,890	7.7%				
Timber	$ 100,867,679	2.0%				
Fixed Income	$ 1,219,916,070	24.4%				
Alternative Investments	$ 724,670,169	14.5%				
Illiquid	$ 358,261,663	7.2%				
Liquid	$ 366,408,506	7.3%				

a/ Totals may not sum due to rounding.
b/ Dominion Resources Pension Fund Investment Performance and Asset Allocation Periods Ending December 31, 2006

Dominion East Ohio
Expected Return on Plan Assets - Sensitivity

Impact on 2007 expense of change in long term expected return on assets:		Union Pension Plans
Increase 25 basis points	a/	$ (1,654,108)
Decrease 25 basis points	a/	$ 1,654,108

a/ Includes amounts applicable to East Ohio Gas, River Gas Division, and West Ohio Gas Division plans applicable to DEO's union employees.

Source: Watson Wyatt Actuarial Valuations as of January 1, 2006, issued April 11, 2007 for Dominion Pension Plans, Table 1, page 9.

Managing Director

Expert Witness, Regulatory Strategy, Litigation, Financial Analysis, Cost of Service, Cost Allocation, Rate & Tariff Design, M&A Due Diligence

Education
Certified Public Accountant
State of Maryland
(inactive status)
B. S., Business and Commerce
University of Maryland -1975
B. A., Liberal Arts
University of Maryland - 1970

Total Years Experience
30

Joined Lukens Energy Group
1999

Professional Associations
American Gas Association - Rate & Strategic Planning Committee
Associate Member, 2002-Present
Chair, 1997
Vice Chair, 1995-1996
Member, 1987-1995
American Gas Association
Associate Member
1999-Present
American Public Gas Assoc.
Associate Member 2000-Present
American Institute of Certified Public Accountants
Member
Houston Energy Association
Member 1999-2003
Energy Bar Association
Associate Member 2002-Present
Texas Society of Certified Public Accountants – Houston Chapter
Member 2003-Present

Language Capabilities
English

Dan Ives is a Managing Director with the Enterprise Management Solutions Division of Black & Veatch Corporation. He has thirty years of energy industry experience primarily in leadership positions at three major natural gas pipeline and distribution companies in the area of rates and regulatory affairs. Mr. Ives' consulting focus is on assisting clients in maximizing business opportunities through rates and regulatory strategy, project development, and the financial management process. He also provides regulatory training services and litigation and regulatory support, including expert testimony on such matters as natural gas costs, cost of service, cost allocation, and rate and tariff design.

Representative Project Experience

Alaska Natural Gas Pipeline
Mr. Ives assisted outside counsel for the State of Alaska's Department of Law develop and evaluate regulatory positions and responses to proposed Federal regulation related to the Alaska Natural Gas Pipeline Project. Mr. Ives made a presentation to the Alaskan joint legislative committee describing the Federal regulatory process and pipeline open season practices.

Oil Pipeline Rate Proceeding
Mr. Ives testified on behalf of the State of Alaska in the TransAlaska Pipeline System's 2005 and 2006 interstate oil transportation rate filings with the Federal Energy Regulatory Commission ("FERC") with respect to his development of a cost-based reference rate for use in the remedy of rate discrimination.

Gas Distribution Risk Consequence Analysis
Mr. Ives developed a forward-looking risk consequence-based analytical approach to pipeline replacement for a major natural gas distribution company. The project analyzed industry and utility leak data to determine the consequences of pipeline and service line leaks on a population density-adjusted basis. Mr. Ives also prepared expert testimony for the utility.

Pipeline Open Access Interstate Certificate Application
Mr. Ives assisted an intrastate pipeline company prepare an application for a Certificate of Public Convenience and Necessity to convert the pipeline to an interstate pipeline subject to FERC regulation. The project included preparation of cost of service adjustments, cost allocation studies, and rate design, including a distance-sensitivity study to support zone rates. Mr. Ives also prepared various supporting schedules for the application and assisted Client with presentations before Federal regulatory personnel in advance of filing the application.

Pipeline Cost Service Study
Mr. Ives prepared a cost of service study for an intrastate pipeline in support of transportation and storage services rendered to an electric utility affiliate. Dan presented expert testimony before the Oklahoma State Commerce Commission in support of the study.

Revenue Stabilization Adjustment Mechanism ("RSAM")
Mr. Ives developed an RSAM for a major Southeast natural gas distribution utility to recoup revenues otherwise lost to the adverse affects of weather,

declining use per customer, and customer attrition. Mr. Ives also prepared tariff language and computational schedules in support of the mechanism, along with a regulatory presentation.

Gas Strategy Development
The Cove Point and Elba Island LNG terminals have dramatically changed the natural gas market in the Southeastern U.S. Mr. Ives and the project team analyzed the implications to natural gas basis and pipeline flows in the Southeast from these LNG terminals and their associated expansions. Using the firm's proprietary models, the project forecasted how basis may change in the region under different pipeline expansion scenarios. Based on the results of this analysis, the team assisted the Client develop upstream pipeline capacity strategies and expansion strategies for its intrastate pipeline affiliate.

Expert Testimony

Algonquin Gas Transmission Company
United States of America before the Federal Energy Regulatory Commission, Algonquin Gas Transmission Company, Docket No. RP 93-14-000. Prepared Direct Testimony on behalf of Algonquin filed on November 6, 1992. Policy testimony on rate design and the proposed rate increase and introduction of Algonquin's other witnesses. Supplemental Direct Testimony filed on behalf of Algonquin reviewing Commission policy on the showings necessary in order to roll-in incremental rates. Rebuttal Testimony was filed in response to various depreciation, cost classification, cost allocation, rate design and tariff matters, including the design of backhaul rates - a limited issue that was set for hearing. Additional Rebuttal Testimony filed on rolled-in rate issues.

Empire State Pipeline Company
State of New York before the Public Service Commission, Empire State Pipeline Case 95-G-1002. Prepared direct testimony on behalf of Empire State Pipeline Company supporting the general policy issues of the rate filing and introducing company witnesses, adopted July 16, 1996 at an evidentiary hearing. The case settled and the Commission issued an order of approval effective September 24, 1996.

Energas Company
Before the Railroad Commission of Texas, Petition of Energas Company for Review of the Rate Action of Lamesa, Texas (and other cities), GUD Docket No. 9002-9135. Prepared direct testimony filed on March 7, 2000 on behalf of Energas Company, a unit of ATMOS Energy Corporation. Also filed rebuttal and supplemental rebuttal testimony and stood cross-examination. The testimony sponsored a class cost of service and a proposed revised declining block rate design, as well as a proposed system expansion rider, a steel pipe replacement rider, and revisions to miscellaneous service charges. The parties settled the case.

Enogex Inc.
Before the Corporation Commission of the State of Oklahoma, Application of Oklahoma Gas and Electric Company, Cause No. PUD 200300226. Prepared direct testimony filed April 9, 2004 on behalf of Enogex Inc., a wholly-owned subsidiary of Oklahoma Gas and Electric Company ("OG&E"). The testimony describes and explains a cost of service study that was prepared for the natural gas transportation and storage services that Enogex provides to OG&E. Stood cross-examination in September 2004.

Frederick Gas Company, Inc.
Before the Public Service Commission of Maryland, Case No. 8213. Prepared Direct Testimony filed on October 6, 1989 on behalf of Frederick Gas Company, Inc. in its general rate case. The testimony describes a stipulation and Agreement reached by the parties to the proceeding and provides supporting information for the settlement rates.

Before the Public Service Commission of Maryland, Case No. 8510. Prepared Direct Testimony filed December 3, 1985 on behalf of Frederick Gas Company, Inc. The testimony describes cost savings to firm customers as a result of Frederick's spot market gas purchases and the continued benefit of Frederick's special contract interruptible sales program.

Hope Gas, Inc. (DBA "Dominion Hope")
Before the Public Service Commission of West Virginia, Case No. 01-0330-G-42T and Case No. 01-0331-G-30C. Prepared rebuttal testimony filed September 19, 2001 on behalf of Dominion Hope. The testimony describes and supports Hope's proposed adjustment related to the regulatory treatment of its negative pension expense and related issues. The parties settled the case.

Before the Public Service Commission of West Virginia, Case No. 05-0304-G-42T. Prepared rebuttal testimony filed September 23, 2005 on behalf of Dominion Hope. The testimony describes and supports Hope's proposed adjustment related to the regulatory treatment of its negative pension expense and related issues. The parties settled the case.

Philadelphia Gas Works
Before the Pennsylvania Public Utility Commission, Case No. R-00017034. Prepared Direct Testimony filed February 25, 2002 on behalf of Philadelphia Gas Works (PGW). The testimony describes and supports PGW's proposed Cash Flow ratemaking methodology and PGW's Cash Working Capital requirements.

SCANA Energy Marketing, Inc.
Before the Georgia Public Service Commission, Docket No. 16682-U. Prepared Direct Testimony filed April 25, 2003 on behalf of SCANA Energy Marketing, Inc. (SEMI). The testimony supports SEMI's proposed Plan of Assignment for upstream pipeline assets utilized to serve customers on Atlanta Gas Light Company's system and my specific testimony addresses capacity management accounting and cost allocation issues, as well as benefits to consumers under SEMI's plan. A Hearing was held June 24-25, 2003 in Atlanta, GA.

South Carolina Electric and Gas Company
Before the Public Service Commission of South Carolina, Docket No. 2003-5-G. Prepared Direct Testimony filed September 16, 2003 on behalf of South Carolina Electric and Gas Company ("SCE&G"). The testimony (1) provides an overview of the natural gas markets, (2) describes how SCE&G purchases its reliable and diverse gas supply from South Carolina Pipeline Corporation ("SCPC"), (3) discusses SCE&G's utilization of SCPC's intrastate pipeline system, (4) describes SCE&G's responsibilities were it to purchase its own gas supply, and (5) concludes that SCE&G's gas supply during the review period was reasonable and prudent. A Hearing was held at the Commission in Columbia, SC on October 16, 2003.

South Carolina Pipeline Corporation
Before the Public Service Commission of South Carolina, Docket No. 2001-220-G. Prepared Direct Testimony filed January 21, 2002 on behalf of South Carolina Pipeline Corporation (SCPC). The testimony supports SCPC's cost allocation, cost classification, and natural gas transportation and storage rate designs as well as various pro forma adjustments to implement open access gas transportation. The testimony also supports various tariff proposals including stranded cost recovery and a term rate differential. In February 2002, SCPC withdrew its rate case application.

Before the Public Service Commission of South Carolina, Docket No. 2002-6-G. Delivered an oral presentation with slides on a "Review of Natural Gas Hedging Programs" on behalf of South Carolina Pipeline Corporation at a meeting of the Commission on December 19, 2002. The presentation provided a review of various Eastern U.S. gas companies' hedging programs along with an analytical approach to quantification of the appropriate amount to hedge.

State of Alaska - Department of Law
Before the State of Alaska Legislative Budget and Audit Committee and Senate Resources Committee, Interim Hearings – Alaska Natural Gas Pipeline Issues. Delivered an oral presentation with slides on June 16, 2004 in Anchorage, AK on the topic "What Agreements Must Be Reached Before the Federal Energy Regulatory Commission Weighs In on Tariff Issues." The presentation provided a review of the pipeline Open Season process, Precedent and Service Agreements, the FERC Certificate of Public Convenience and Necessity process and related regulatory requirements, and potential certificate conditions.

United States of America before the Federal Energy Regulatory Commission, Docket Nos. IS05-82 et al, OR05-2 et al, and IS06-70 et al. Filed prepared Answering testimony on May 26, 2006 and Reply testimony on August 11, 2006 on behalf of the State of Alaska – Department of Law in the matter of the TAPS Carriers' 2005 and 2006 interstate oil transportation rate filings with respect to development of a cost-based reference rate for use in the remedy of rate discrimination. Mr. Ives stood cross examination on December 8 and 11, 2006.

TXU Gas Distribution
Before the Railroad Commission of Texas, Docket GUD No. 9313, Petition for Review of TXU Gas Distribution From the Actions of the Cities of Arlington, et al.
Prepared Direct Testimony filed July 15, 2002 on behalf of TXU Gas Distribution (TXU). The testimony describes and explains TXU's cost allocation, rate design, and proposed new tariff provisions "Charge for Temporary Discontinuance of Service" and "Uncollectible Recovery Adjustment." Additionally, the testimony describes and supports the Company's proposed revised tariffs for gas service.

United Cities Gas Company
Before the Illinois Commerce Commission, Docket No. 00-0228. Prepared Direct Testimony filed February 17, 2000 on behalf of United Cities Gas Company, a unit of ATMOS Energy Corporation. The testimony described and supported a Class Cost of Service Study, declining block rate design, and weather normalization of sales and transport volumes.

Before the Virginia State Corporation Commission, Docket No._____. Prepared Direct Testimony filed July 6, 2000 on behalf of United Cities Gas Company, a unit of ATMOS Energy Corporation. The testimony describes and supports a Class Cost of Service Study, declining block rate design, and tariff revisions for temporary discontinuance of service and new customer connections.

Washington Gas Light Company
United States of America before the Federal Energy Regulatory Commission, Transcontinental Gas Pipe Line Corporation, Docket No. RP83-137-000. Prepared Direct Testimony on behalf of Washington Gas Light Company filed on December 13, 1984. The testimony supported fully allocated cost-based rates for firm transportation service within a customer's contract entitlement and discounted interruptible transportation rates for service in excess of a customer's firm contract level. Rebuttal Testimony filed January 24, 1985.

United States of America before the Federal Energy Regulatory Commission, Transcontinental Gas Pipe Line Corporation, Docket No. RP82-55-000.
Prepared Direct Testimony on behalf of Washington Gas Light Company filed on December 9, 1983. The testimony addressed Transco's proposed minimum commodity bill, its proposed Fixed-Variable rate design, and its proposed redesign of small customer rates.

Before the Public Service Commission of Maryland, Case No. 7962.
Oral presentation made before the Commission at public hearings on gas transportation September 25-26, 1986. Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company (WGL), and on behalf of Frederick Gas Company, Inc., a WGL subsidiary, filed on April 22, 1987. The testimony describes and supports proposed tariff provisions for firm and for interruptible delivery service by the companies and a proposed special purchases/sales rider for Frederick's low-priority interruptible gas sales. Rebuttal testimony subsequently filed as the case progressed.

Before the Public Service Commission of Maryland, Case No. 8060. Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company, filed on March 1, 1988. The testimony describes and supports proposed tariff provisions and rates for interruptible delivery service and a margin-sharing tariff provision.

Before the Public Service Commission of Maryland, Case No. 8119. Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company, filed on March 7, 1988. The testimony describes and supports a proposed declining block rate design with a monthly customer charge in the company's general rate case. The testimony also describes and supports proposed tariff changes to change or initiate turn-off and reconnection charges, service initiation fees, and rates and charges for unmetered gaslights. Rebuttal testimony was subsequently filed in the proceeding.

Before the Public Service Commission of Maryland, Case No. 8191. Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company, filed on March 31, 1989. The testimony describes and supports a proposed declining block rate design with a monthly customer charge in the company's general rate case. The testimony also describes and supports proposed rate revisions for delivery service and for unmetered gaslight service and a proposal to retain margins on new interruptible services pending recovery of investment. Supplemental Direct Testimony was filed on June 16, 1989 to reflect actualized data for the test year.

Before the Public Service Commission of Maryland, Case No. 7131, Phase XIII. Prepared Direct Testimony filed on behalf of Washington Gas Light Company and Frederick Gas Company, Inc. Hearing Date of December 6, 1983. The testimony describes the companies' participation in the special gas transportation programs of its pipeline suppliers during the period June 1983-November 1983 and the resultant cost savings to consumers.

Before the Public Service Commission of Maryland, Case No. 7131, Phase XIV. Prepared Direct Testimony filed on behalf of Washington Gas Light Company and Frederick Gas Company, Inc. Hearing Date of June 20, 1984. The testimony describes the companies' participation in the special gas transportation programs of its pipeline suppliers during the period December 1983-May 1984 and the resultant cost savings to consumers. The testimony also discusses the companies' activities before the FERC involving its pipeline suppliers.

Before the Public Service Commission of Maryland, Case No. 7131, Phase XV. Prepared Direct Testimony filed on behalf of Washington Gas Light Company and Frederick Gas Company, Inc. Hearing Date of December 11, 1984. The testimony describes the companies' participation in pipeline suppliers' special marketing programs and direct producer purchases during the period June 1984-November 1984. The testimony also discusses the companies' activities before the FERC involving its pipeline suppliers.

Before the Public Service Commission of Maryland, Case No. 8509. Prepared Direct Testimony filed on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. Hearing Date of December 6, 1985. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period June 1985-November 1985, the costs of which supplies were not determined by regulation. The testimony also identifies the benefits from special contract sales credited to firm customers through the Firm Credit Adjustment.

Before the Public Service Commission of Maryland, Case No. 8509(a). Prepared Direct Testimony filed on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. Hearing date of June 11, 1986. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period December 1985-May 1986, the costs of which were not determined by regulation. The testimony also identifies the benefits from special contract sales credited to firm customers through the Firm Credit Adjustment and the testimony identifies and describes the company's participation in cases before the FERC.

Before the Public Service Commission of Maryland, Case No. 8509(c). Prepared Direct Testimony filed on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. Hearing Date of May 7, 1987. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period December 1986-May 1987, the costs of which were not determined by regulation.

Before the Public Service Commission of Maryland, Case No. 8509(d). Prepared Direct Testimony filed December 3, 1987 on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period June 1987-November 1987, the costs of which were not determined by regulation.

Before the Public Service Commission of Maryland, Case No. 8509(j). Appeared as a supplemental direct witness at the hearing on November 30, 1990 to present oral testimony regarding the operation of the company's Firm Credit Adjustment mechanism and the computation of margins, particularly with respect to sales to Potomac Electric Power Company.

Western Kentucky Gas Company
Before the Public Service Commission of Kentucky, Case No. 99-070 (1999). Filed testimony on behalf of Western Kentucky Gas Company, a unit of ATMOS Energy Corporation, to describe and support a proposed Premises Charge to recover from new customers the incremental investment, and return and tax, associated with new residential customer hook-ups that is not otherwise recovered in base rates. The parties settled the case.

Publications and Research

"Calming Stormy Seas," (co-authored with Deepa Poduval) an article published in the November 2003 issue of American Gas, a monthly publication of the American Gas Association. The article discusses measures that utilities can utilize to reduce exposure to natural gas price volatility.

"Weather Risk Management for Regulated Utilities," (co-authored with Thomas Jenkin) an article published in the October 1, 2002 issue of Public Utilities Fortnightly, a publication of Public Utilities Reports, Inc. The article discusses methods of quantifying weather risk and options for managing the risk through the use of derivatives and weather normalized rates.

"Those Paper Pension Profits," an article published in the September 15, 2000 issue of Public Utilities Fortnightly, a publication of Public Utilities Reports, Inc. The article discusses the regulatory treatment of negative pension expense and offers strategies for managing the risk of pension expense credits being flowed-through in rates.

"How Stranded Are Your Assets?" an article published in the February 2000 issue of American Gas, a monthly publication of the American Gas Association. The article discusses strategies for utilities to ease the transition to a competitive, market-driven environment.

"The Electric Heat Pump," a paper analyzing the electric heat pump's competitive impacts in the metropolitan Washington, DC heating markets and competitive strategies, June 28, 1985.

Presentations and Speeches

American Gas Association's Advanced Regulatory Seminar:
"Current Rate Design Issues," a speech presented September 28, 1995.

"Local Distribution Rate Design Trends and Opportunities," a speech presented in October 1990 and updated and presented in 1991.

"Current Pricing Issues," a speech presented October 6, 1989.

"Can America Unbundle and Still Keep Warm?" a speech presented October 7, 1988.

"Flexibility in the Changing Market," a speech presented October 5, 1984.

American Gas Association Rate & Strategic Planning Committee Meetings:

"Outlook for the North American Energy Market and Energy Price Fundamentals," a speech presented March 26, 2007 in Phoenix, AZ

"Outlook for the North American Energy Market and Energy Price Fundamentals," a speech presented April 11, 2006 in Coconut Grove, FL

"Distribution System Integrity Management," a speech presented April 12, 2005 in New Orleans, LA

"Natural Gas Fixed Price Tariff Options," a speech presented April 5, 2004 in Phoenix, AZ

"Improving Fixed Cost Recovery," a speech presented March 26, 2002.

"Impacts of Electric Generation on Native Gas Loads," a speech presented March 27, 2001 in Charleston, SC.

"Managing Upstream Resources in a Retail Unbundling World – FERC & Pipeline Perspectives and Responses," a speech presented April 4, 2000.

"Market Hubs – Operation, Economics & Rate Implications," a speech presented August 29, 1994.

"Implications of Capacity Release," a speech presented March 7, 1994.

"Implementing Restructuring," a speech presented March 15, 1993.

"Integrated Resource Planning Theory and Practice," a speech presented in April 1992.

American Gas Association Seminar "Service Innovations and Revenue Enhancements," Washington, DC:

"Improving Fixed Cost Recovery and Stabilizing Earnings – Drivers and Ideas," a speech presented December 12, 2002.

American Gas Association's Seminar "Competing in a Restructured World," Arlington, VA:

"Separation of Functions and Accounting Cost Standards," a speech presented July 9, 1998.

Energy Bar Association, Chicago, IL:

"Back to the Future – Managing Gas Supply in a Time of Price and Supply Uncertainty," a speech presented to the Joint Meeting of the Midwest and East Central Chapters, October 2, 2003.

National Association of Regulatory Utility Commissioners ("NARUC"):

"Natural Gas Fixed Price Tariff Options," a speech presented to the Staff Subcommittee on Accounting and Finance at Rapid City, SD, October 2, 2002.

"Design of Pipeline Rates," a teleconference speech concerning the design of rates for short-term service presented to the Staff Subcommittee on Gas, May 29, 1998.

"Natural Gas Pricing and Rate Design in the 1990s," Seminar in Houston, TX:

"Rate Design Trends and Opportunities," a speech presented September 13, 1990.

"Pricing and Rate Strategies for Unbundled Services," Seminar in Houston, TX:

"Local Distribution Rate and Regulatory Trends and Opportunities," a speech presented October 30, 1990.

Society of Utility and Regulatory Financial Analysts ("SURFA"):

"Perspectives on Weather Risk Management," a speech presented at Georgetown University Conference Center, Washington, DC, April 10, 2003

Southern Gas Association - Accounting Seminar:

"An Update on Customer Choice Programs and Related Accounting and Regulatory Issues," a speech presented in Houston, TX, July 9, 1999.

Texas Society of Certified Public Accountants – Natural Gas, Telecommunications and Electric Industries Conference, Austin, TX:

"Managing Energy Price Risk in a Volatile Environment," a speech presented April 19, 2004.

University of Missouri - Financial Research Institute
"Impact and Responses of Rising Utility Costs," a speech presented in Columbia, MO September 27, 2006.

Training and Teaching Experience

American Gas Association's "Gas Rates Course", University of Wisconsin, Madison, WI:

"Introduction to Regulation and the Ratemaking Process," a lecture, followed by a "Ratemaking Workshop," presented annually in June, 1991 – 2004 and 2006.

"Pipeline Cost Allocation and Rate Design," a lecture and hands-on computer demonstration presented June 6, 1995.

Southern Gas Association's "The Ratemaking Process," held at CenterPoint Energy, Houston, TX:

Led a Mock Rate Case and Case Studies exercise involving 40 students that participated in role playing (Company, Commission, & Intervenors) on several utility ratemaking issues. May 17, 2007.

American Gas Association/Edison Electric Institute's "Introduction to Public Utility Accounting Course," Virginia Commonwealth University, Richmond, VA:

"Introduction to Regulation and the Ratemaking Process," a lecture, followed by a "Ratemaking Workshop," presented annually in May, 1991-1995.

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Authority to Increase Rates for its Gas Distribution Service	)	Case No. 07-829-GA-AIR
In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Approval of an Alternative Rate Plan for its Gas Distribution Service	)	Case No. 07-830-GA-ALT
In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Approval to Change Accounting Methods	)	Case No. 07-831-GA-AAM

DIRECT TESTIMONY OF
MICHAEL J. VILBERT
ON BEHALF OF
DOMINION EAST OHIO

___ Management policies, practice and organization

___ Operating income

___ Rate base

___ Allocations

_X_ Rate of return

___ Rates and tariffs

___ Other

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I. INTRODUCTION AND SUMMARY

Q1. Please state your name and address for the record.

A1. My name is Michael J. Vilbert. My business address is The Brattle Group, 44 Brattle Street, Cambridge, MA 02138, USA.

Q2. Please describe your job and your educational experience.

A2. I am a Principal of The Brattle Group, ("Brattle"), an economic, environmental and management consulting firm with offices in Cambridge, Washington, London, San Francisco and Brussels. My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy and a Ph.D. in finance from the Wharton School of Business at the University of Pennsylvania.

Q3. What is the purpose of your testimony in this proceeding?

A3. I have been asked by Dominion East Ohio (the "Company" or "DEO") to estimate the cost of equity that the Public Utilities Commission of Ohio (the "PUCO" or the "Commission") should allow DEO an opportunity to earn on the equity financed portion of its rate base.

To accomplish this task, I estimate the overall cost of capital for a sample of regulated natural gas local distribution companies ("gas LDCs") using the discounted cash flow ("DCF") and the risk positioning models. I then evaluate the relative risk of DEO compared to the sample companies to determine the recommended cost of equity for a regulatory capital structure with 44.8 percent equity, 0.8 percent preferred, and 54.3 percent debt, which is the Company's proposed capital structure in this proceeding based on its parent company's, Dominion Resources, Incorporated's, consolidated capital structure as of March 31, 2007.

Q4. Please summarize the parts of your background and experience that are particularly relevant to your testimony on these matters.

A4. Brattle's specialties include financial economics, regulatory economics, and the gas and electric industries. I have worked in the areas of cost of capital, investment risk and related matters for many industries, regulated and unregulated alike, in many forums. I have testified or filed cost of capital testimony before the Federal Energy Regulatory Commission, the Arizona Corporation Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of West Virginia, the Tennessee Regulatory Authority, the Public Service Commission of Wisconsin, the South Dakota Utilities Board, the California Public Utilities Board, the Canadian National Energy Board, Alberta Energy and Utilities Board, the Ontario Energy Board, and the Labrador & Newfoundland Board of Commissioners of Public Utilities. I have not previously testified before this Commission, but I submitted testimony on behalf of FirstEnergy's Ohio electric distribution companies in June 2007. Appendix A contains more information on my professional qualifications.

Q5. Please summarize how you approached this task.

A5. I review the evidence from a sample of regulated gas LDC's which were selected to be of comparable business risk to the Company's gas distribution operations in Ohio. My analyses consider cost of capital evidence from the risk positioning and discounted cash flow models, but I rely primarily on the risk positioning results because I do not believe that the DCF method is completely reliable at this time.

Specifically, I estimate the cost of equity for companies in the sample group using both cost-of-equity estimation methods. For each cost-of-equity estimate, I combine the cost of equity estimate with the sample company's market costs of debt and preferred stock to calculate each firm's overall cost of capital, i.e. its after-tax weighted-average cost of capital ("ATWACC"), using each company's market value capital structure as the weights. For each method of estimating the return on equity, I report the sample average ATWACC and the estimated cost of equity for this line of business at a capital structure with 44.8 percent equity. I thus present the cost of equity that is consistent with both the sample's market information and the Company's regulatory capital structure. (By "regulatory capital structure," I mean the capital structure that DEO utilizes in its application.[1])

The use of the overall cost of capital automatically avoids problems that can arise when an analyst focuses separately on the individual components of the overall cost of capital (i.e., the cost of equity and the appropriate capital structure). The danger with that approach is that the estimated cost of equity from the sample may correspond to a very different level of financial risk than would exist at the regulated company's capital structure. The result could be an inconsistency between the allowed return on equity and the financial risk inherent in the regulatory capital structure.

Q6. What is your conclusion on the market-determined cost of capital for DEO based upon the results from the sample of regulated companies you selected?

A6. The best point estimate of the cost of equity for DEO is 12 percent for a capital structure with 44.8 percent equity, 0.8 percent preferred, and 54.3 percent debt, but it is more correct to say that the sample results indicate a range for the cost of equity estimates from 11½ to 12½ percent. The corresponding midpoint of the range of the overall cost of capital estimates, i.e., the ATWACC, for the benchmark sample companies is 7¾ percent with a range of 7½ to 8 percent. Note, that I specify a plus or minus ½ percent range for the return on equity and specify the point estimate to the nearest ¼ percent because I do not believe that it is possible to estimate the cost of equity more precisely than that.

Q7. What are the results for the DCF model?

A7. Results from the simple DCF model and for the multistage model are set out in the accompanying tables. (See Table No. MJV-6, Panel A - simple DCF and Panel B - multistage DCF.) After properly adjusting for the financial risk in the Company's regulatory capital structure, the sample average for the simple DCF model is 10.3 percent and for the multistage DCF model is 10.7 percent (See Table No. MJV-8). The results

[1] The capital structure that I customarily use in these analyses is based upon the long-term sources of capital, i.e., long-term debt, preferred equity and common equity. I do not use short-term debt because long-term assets are not generally financed with short-term debt.

for a sub-sample of companies with fewer data issues are 9.9 percent and 10.6 percent respectively.

Q8. Why do you believe that the DCF model is less reliable for this industry at this time than the risk positioning model?

A8. Results for the DCF model depend critically on the estimate of the dividend growth rate. A one percentage point error in the estimate of the growth rate results in a greater than one percentage point error in the cost of equity estimates. Natural gas prices have increased substantially and have become much more volatile recently compared to just a few years ago, which has affected the demand for natural gas. Although all of the companies in the sample have fuel cost adjustment clauses, the increased volatility of gas prices has increased the uncertainty of the industry's earnings going forward because full cost recovery on a timely basis is not guaranteed. The electric industry is a major source of demand for natural gas and it, too, is undergoing a period of uncertainty surrounding the ultimate structure of the industry. In addition, the potential imposition of additional environmental and safety restrictions on both the natural gas industry and the electric industry increases the uncertainty about future growth in earnings. For example, implementation of distribution integrity management rules to be introduced within the next year will inevitably lead to substantial capital and O&M expenditures among gas LDCs nationwide.[2] Uncertainty regarding the timely recovery of and return on these expenditures is likely to affect analysts' earnings forecasts. There have also been a number of mergers and acquisitions in the industry which may have the effect of increasing the market prices of the companies in the industry even if they are not the immediate target of a takeover which thereby reduces the dividend yield. These facts are not a description of an industry that could be characterized as stable with earnings and

---

[2] See "Distribution Integrity Management Program – Rulemaking is Under Way," *American Gas*, July 2007, pp. 12-16. However, according the American Public Gas Association's website, "APGA has learned that the proposed Distribution Integrity Management Program (DIMP) rule will not be issued until sometime this Fall due to concerns about the cost-benefit analysis. This means that the final rule will likely not take effect until sometime in 2008. This provides operators with additional time to prepare for this major rulemaking. APGA, through the Security and Integrity Foundation (SIF), is developing a model DIMP plan to assist public gas systems to develop written DIMP programs. The model plan will be available when the final rule is issued sometime next year."

dividends likely to grow at a constant rate over the foreseeable future, but that is precisely the condition necessary for the reliable implementation of the DCF model.

Although the DCF model results are less reliable than those based upon the risk positioning model at this time, I provide results using the DCF method, because it is a method that has been relied upon by commissions frequently in the past. In addition, results from the DCF model serve as a check on the results from the equity risk positioning approach.

Q9. What are the results for the risk positioning model?

A9. The sample average risk positioning results, again adjusted for differences in financial risk, range from 12.7 to 13.0 percent for the full sample, when using the long-term risk-free rate, and 12.4 to 12.7 percent for the sub-sample. I also report results for the risk positioning model using the short-term risk-free rate which are about 30-70 basis points ("bps") higher than for the long-term version of the model, but I place very little weight on those estimates in this proceeding because short-term interest rates have been quite variable lately. (See Table No. MJV-12 or Table 3 on page 35 below.)

Q10. You mentioned the importance of considering financial risk when evaluating the results of the models. Please explain how you adjust for financial risk.

A10. Both the DCF and the risk positioning models rely on market data to estimate the cost of equity for the sample companies. Those cost of equity estimates capture both the business risk and the financial risk of the sample companies' stocks. Business risk is the risk that the company would have if it were financed entirely with equity. Financial risk is the additional risk carried by the equity holders when debt is used to finance some of the assets. The more debt that is used by a company, the riskier the company's equity becomes. As explained in more detail below, the procedures I use consider both the business risk and the financial risk of the sample companies in comparison to DEO in determining my recommended cost of equity.

Q11. How is your testimony organized?

A11. *Section II* formally defines the cost of capital and touches on the principles relating to the cost of capital and capital structure for a business. *Section III* presents the methods used to estimate the cost of capital for the benchmark sample and the associated numerical analyses, and explains the basis of my conclusions for the benchmark sample's returns on equity and overall costs of capital. *Section IV* presents the results of these methods applied to the benchmark sample group, and presents the costs of equity implied by the results. My conclusions on the cost of equity for the Company are presented in *Section V.* Appendix B provides additional details on the selection of the sample and the calculation of the market value capital structures of the sample companies. Appendices C and D support *Sections III and IV* with additional details on the risk positioning model and DCF approach, respectively, including the details of the numerical analyses. Appendix E discusses the effect of debt on the cost of equity in more detail.

II. COST OF CAPITAL THEORY

A. The Cost of Capital and Risk

Q12. Please formally define the "Cost of Capital."

A12. The cost of capital can be defined as *the expected rate of return in capital markets on alternative investments of equivalent risk.* In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected" in this testimony, as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

The definition of the cost of capital recognizes a tradeoff between risk and return that is known as the "security market risk-return line," or "security market line" for short. This line is depicted in Figure 1. The higher the risk, the higher is the cost of capital. A version of Figure 1 applies for all investments. However, for different types of securities, the location (i.e., the intercept and the slope) of the line may depend on corporate and personal tax rates.

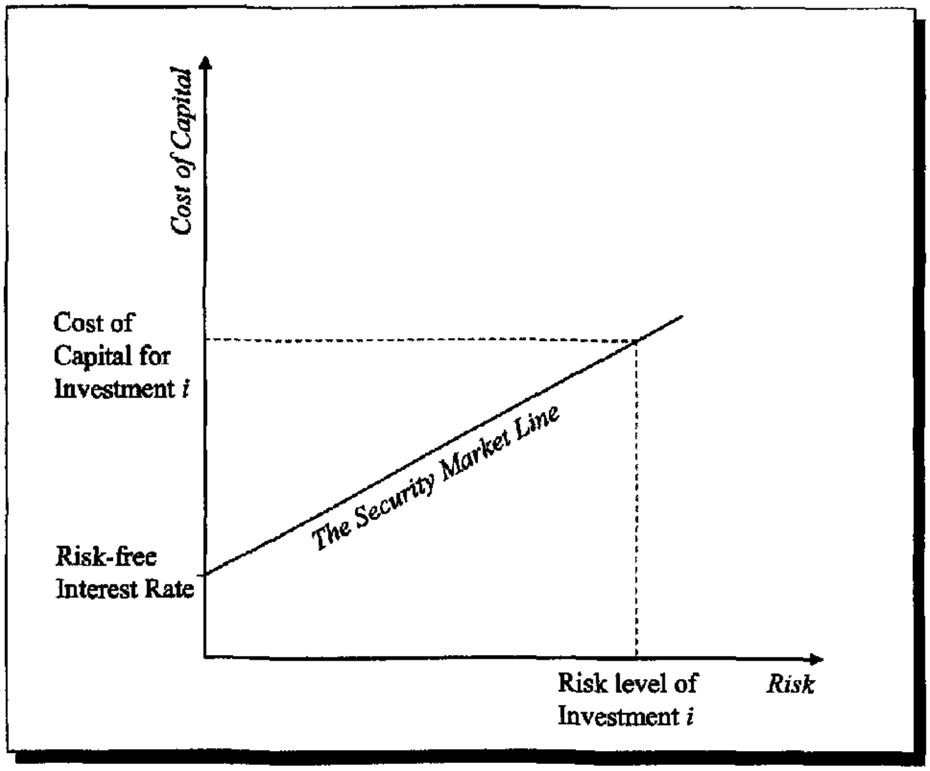

Figure 1: The Security Market Line

Q13. Why is the cost of capital relevant in rate regulation?

A13. It has become routine in U.S. rate regulation to accept the "cost of capital" as the right expected rate of return on utility investment.[3] That practice is normally viewed as consistent with the U.S. Supreme Court's opinions in *Bluefield Waterworks & Improvement Co. v. Public Service Commission*, 262 U.S. 678 (1923), and *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591 (1944).

From an economic perspective, rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers overpay

[3] A formal link between the cost of capital as defined by financial economics and the right expected rate of return for utilities is established by Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases," *The Bell Journal of Economics and Management Science*, 3:58-97 (Spring 1972).

for service. Regulatory commissions normally try to prevent such outcomes, unless there are offsetting benefits (e.g., from incentive regulation that reduces future costs). At the same time, an expected return below the cost of capital does a disservice not just to investors but, importantly, to customers as well. In the long run, such a return denies the company the ability to attract capital, to maintain its financial integrity, and to expect a return commensurate with that of other enterprises attended by corresponding risks and uncertainties.

More important for customers, however, are the economic issues an inadequate return raises for them. In the short run, deviations of the expected rate of return on the rate base from the cost of capital may seemingly create a "zero-sum game"-- investors gain if customers are overcharged, and customers gain if investors are shortchanged. But in fact in the short run, such action may adversely affect the utility's ability to provide stable and favorable rates because some potential efficiency investments may be delayed or because the company is forced to file more frequent rate cases. In the long run, inadequate returns are likely to cost customers – and society generally – far more than is gained in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. The costs of an undercapitalized industry can be far greater than the short-run gains from shortfalls in the cost of capital. Moreover, in capital-intensive industries (such as the natural gas distribution industry), systems that take a long time to decay cannot be fixed overnight. Thus, it is in the customers' interest not only to make sure the return investors expect does not exceed the cost of capital, but also to make sure that it does not fall short of the cost of capital, either.

Of course, the cost of capital cannot be estimated with perfect certainty, and other aspects of the way the revenue requirement is set may mean investors expect to earn more or less than the cost of capital even if the allowed rate of return equals the cost of capital exactly. However, a commission that sets rates so investors expect to earn the cost of capital on average treats both customers and investors fairly, and acts in the long-run interests of both groups.

B. Business Risk & Financial Risk: Capital Structure and the Cost of Equity

Q14. Please explain briefly the difference between business risk and financial risk.

A14. Business risk is the risk of a company from its line of business if it used no debt financing. When a firm uses debt to finance its assets, the business risk of the assets is shared between the debt holders and the equity holders, but the equity holders bear more of the risk because debt holders have a prior claim on the company's cash flows. Equity holders are residual claimants, which simply means that equity holders get paid last. In other words, the use of debt imposes financial risk on the equity holders. Therefore, the goal of selecting a sample is to choose companies whose business risk is judged to be comparable to that of the Company's gas distribution operations in Ohio.

Q15. Please explain why it is necessary to report the cost of equity adjusted for capital structure.

A15. Briefly, rate regulation in North America tends to focus on the components of the overall cost of capital, and in particular, on what the "right" cost of equity and capital structure should be. Frequently, there is no consideration of whether the financial risks of the sample companies differ among themselves or differ from the regulated company. The cost of equity estimated using the standard models (e.g., the DCF model or the risk positioning model) reflects both the business and financial risk of the sample companies. The cost of equity estimates for the sample companies will vary, in part, due to small differences in business risk and, in part, due to differences in financial risk. However, the overall cost of capital depends primarily on the business the firm is in, i.e., the business risk of the company's assets, while the costs of the debt and equity components depend not only on this business risk alone but also on the distribution of revenues between debt and equity, i.e. financial risk. The overall cost of capital is thus the more basic concept. The overall cost of capital is constant within a broad middle range of values of capital structures, but the distribution of the costs and risks among debt and equity is not. Appendix E sets out the principles and procedures on which I rely.

C. IMPLICATIONS FOR ANALYSIS

Q16. Please explain the implications of the relationship between capital structure and the cost of equity in your testimony.

A16. The risk equity holders bear, and therefore the cost of equity, depends on the capital structure. As leverage increases, financial risk increases, and hence the required return on equity increases. An approach that estimates the cost of equity for each of the sample firms without explicit consideration of the market value capital structure (i.e., the financial risk) underlying those costs risks material errors. The costs of equity of the sample companies at their actual market-value capital structures do not necessarily reflect the same degree of financial risk as faced by equity holders in the regulated company, and thus could lead to an unfair rate of return if the sample's cost of equity estimate were simply and mechanically applied to the regulated company's capital structure. I avoid this problem by calculating each sample company's ATWACC using its market value capital structure. Using the sample's average overall cost of capital (i.e., the average of the sample companies' ATWACCs) as an estimate of the Company's overall cost of capital, I then determine the corresponding return on equity at the Company's filed regulatory capital structure. This procedure ensures that the capital structure (i.e., financial risk) and the estimated cost of equity are consistent with the market derived sample information.

In the following analyses, I estimate the cost of equity for each of the sample firms using the DCF and risk positioning estimation methods. I use each company's estimated cost of equity along with the Company's estimated 2008 marginal income tax rate[4] and each sample company's cost of debt and market-value capital structure to estimate the company's overall cost of capital. I then calculate the sample's average overall cost of capital for each equity estimation method. Using the procedure discussed above, I then determine the cost of equity at DEO' regulated capital structure that is consistent with the sample's overall cost of capital information for each estimation method.

[4] Ohio levies no state income tax on regulated utilities so the marginal tax rate is equal to the 35 percent federal income tax rate. Instead, utilities pay a gross receipts tax.

Q17. To assess the magnitude of financial risk for a rate regulated company, should you use the market-value or the book-value capital structure?

A17. The market-value capital structure is the relevant quantity for analyzing the cost of equity evidence, which is based on market information.

Q18. Has the need to use market-value capital structures to estimate the cost of equity been widely recognized in the academic community?

A18. Yes. The need to use market-value capital structures to analyze the effect of debt on the cost of equity has been recognized in the financial literature for a long time. For example, the initial reconciliation of the Modigliani-Miller theories[5] of capital structure with the Capital Asset Pricing Model, in Robert S. Hamada, "Portfolio Analysis, Market Equilibrium and Corporate Finance," The Journal of Finance 24: 13-31 (March 1969) works with market-value capital structures. For a more recent presentation of the concept, see, for example, Richard A. Brealey, Stewart C. Myers, and Franklin Allen, *Principles of Corporate Finance*, New York: McGraw-Hill/Irwin 8th ed. (2006) pp. 503-06. Book values may be relevant for some issues, e.g., for covenants on individual bond issues, but as explained in the text, market values are the determinants of the impact of debt on the cost of equity.

Q19. Is the use of market values to calculate the impact of capital structure on the risk of equity incompatible with use of a book-value rate base for a regulated company?

A19. No. The cost of capital is the fair rate of return on regulatory investment (i.e., rate base) for both investors and customers. Most regulatory jurisdictions in North America measure the rate base using the net book value of assets, not current replacement value or historical cost trended for inflation, but the jurisdictions still apply market-derived measures of the cost of equity (such as derived from the DCF or the risk positioning models) to that net book value rate base.

[5] The basic idea of the Modigliani-Miller theories is that the required return on equity increases with the amount of debt in the capital structure, but the overall cost of capital remains constant within a broad middle range of capital structures. See Appendix E, Section I.A. for a more detailed discussion of the Modigliani-Miller theories regarding the effect of debt on a company's overall cost of capital.

The issue here is "what level of risk is reflected in that cost of equity estimate?" That equity risk level depends on the sample company's market-value capital structure, not its book-value capital structure. *That risk level would be different if the sample company's market-value capital structure exactly equaled its book-value capital structure, so the estimated cost of equity would be different, too.*

Q20. Please sum up the implications of this section.

A20. The market risk, and therefore the cost of equity, depends directly on the market-value capital structure of the company or asset in question. It therefore is impossible to compare validly the measured costs of equity of different companies without taking capital structure into account. Capital structure and the cost of equity are unbreakably linked, and any effort to treat the two as separate and distinct questions violates both everyday experience (e.g., with home mortgages as shown in the extended example in Appendix E) and basic financial principles.

Q21. How should a cost of capital analyst implement the principle that the cost of equity changes as financial risk changes?

A21. As discussed further in Appendix E, there has been a great deal of financial research on the effects of capital structure on the value of the firm. One of the key conclusions that results from the research is that no narrowly defined optimal capital structure exists within industries, although the typical range of capital structures does vary among industries.[6] Instead, there is a relatively wide range of capital structures within any industry in which fine-tuning the debt ratio makes little or no difference to the value of the firm, and hence to its overall after-tax cost of capital.

Accordingly, analysts should treat the market-value weighted average of the cost of equity and the after-tax current cost of corporate debt, or the "ATWACC" for short,[7] as

[6] An exception is that very high-risk industries should avoid debt entirely, which makes their optimal capital structure zero percent debt.

[7] This quantity typically is called the "weighted-average cost of capital" or "WACC" in finance textbooks. The textbook WACC equals the *market*-value weighted average of the cost of equity and the *after-tax, current* cost of debt. However, rate regulation in North America has a legacy of working with another, and very different, weighted-average cost of capital, the *book*-value weighted average of the cost of equity and

constant within a broad middle range of capital structures for the industry. Sample evidence should be analyzed to determine the sample's average ATWACC, which can be compared across different firms or industries. The economically appropriate cost of equity for a regulated firm is the quantity that, when applied to the *regulatory* capital structure, produces the same ATWACC. That value is the cost of equity that the sample would have had estimation problems aside, if the sample's market-value capital structure had been equal to the regulatory capital structure in question.

Q22. Can you provide an example of the calculation of the cost of equity consistent with the market-determined estimate of the sample's average overall cost of capital?

A22. Yes. Consider the following equation to calculate the ATWACC:[8]

$$ATWACC = r_D \times (1 - T_C) \times D + r_E \times E \qquad (1)$$

where r_D = market cost of debt,
r_E = market cost of equity,
T_C = corporate income tax rate,
D = percentage of debt in the capital structure, and
E = percentage of equity in capital structure.

The cost of equity consistent with overall cost of capital estimate (ATWACC), the market cost of debt and equity, the marginal corporate income tax rate and the amount of debt and equity in the capital structure can be determined by solving equation (1) for r_E.

D. The Company's Regulatory Capital Structure

Q23. What is the basis of the Company's filed regulatory capital structure in this proceeding?

A23. The regulatory capital structure for the Company in this proceeding is based upon the March 31, 2007 consolidated capital structure of its parent company, Dominion

the *before-tax, embedded* cost of debt. Accordingly, in regulatory settings it's useful to refer to the textbook WACC as the "ATWACC," or "after-tax weighted-average cost of capital." I follow that practice here.

[8] Note that this equation assumes that only debt and equity are in the capital structure, but preferred equity can be added to the equation if appropriate.

Resources, Inc. ("DRI").[9] The underlying information supporting the filed capital structure is included in Schedules D-1 to D-4 (revised) which are attached to this testimony as Appendix F.[10] As of March 31, 2007, DRI's consolidated capital structure was approximately 44.8 percent equity, 0.8 percent preferred equity and 54.3 percent debt as shown on Schedule D-1.[11]

Q24. What is the source of the data for the capital structure shown on Schedules D-1 to D-4?

A24. The source of the data is DRI's financial information as published in its Form 10-Q as of March 31, 2007. (See footnote 9.)

Q25. Why is it appropriate to use the Company's parent company's consolidated capital structure in this proceeding?

A25. It is appropriate to use DRI's consolidated capital structure for two reasons: 1) going forward, DRI will provide debt and equity financing for Dominion East Ohio, and 2) in the past, the Commission has favored use of the parent company's consolidate capital structure particularly when the parent is the source of financing for the operating company.

However, the use of the ATWACC approach makes the source of the regulatory capital structure less important than it would be if the return on equity were set without regard to the capital structure, because the recommended return on equity changes as the regulatory capital structure changes in order to maintain a constant ATWACC. Note in particular that using the constant ATWACC approach results in no change in the cost to ratepayers as the capital structure changes.

Q26. What information is provided in Schedules D-1 to D-4?

A26. Schedule D-1 provides the consolidated capital structure and the embedded costs of debt and preferred equity based upon the information in Schedules D-2 to D-4. Schedule D-1

[9] Financial information was obtained from DRI's (unaudited) financial statements as reported in their first quarter 2007 Form 10-Q. More detailed information was also provided directly by DRI.

[10] Schedules D-1 to D-4 attached to this testimony are the revised versions not the versions originally filed.

[11] The percentages do not add to 100 percent due to rounding.

also demonstrates the calculation of the 8.72 percent regulatory weighted-average cost of capital ("WACC") for DEO in this proceeding.[12] The regulatory WACC reflects the weighted-average of the embedded costs of long-term debt and preferred stock as well as the 12 percent return on equity that I recommend using the capital structure percentages as weights.

Q27. Please describe the information contained in Schedules D-2 through D-4.

A27. Schedule D-2 entitled "Embedded Cost of Short-Term Debt," Schedule D-3 entitled "Embedded Cost of Long-Term Debt," and Schedule D-4 entitled "Embedded Cost of Preferred Equity," provide the calculations of the embedded costs of short-term debt, long-term debt and preferred equity, respectively.

Q28. Please comment on the parent company information presented in Section D.

A28. The Standard Filing Requirements for Schedule D-3 quantify the embedded cost of long-term debt by dividing Annual Interest Cost by Carrying Value, which is calculated as:

Carrying Value equals	Face Amount Outstanding
	+ Unamortized (Discount) or Premium
	- Unamortized Debt Expense
	+ Unamortized Gain (Loss) on Reacquired Debt

On Schedule PCD-3, DEO includes additional information that it is subsequently reflected in Schedule PCD-1 to establish the overall rate of return requested by the Company. To be more specific, DEO has added a column for Other Related Unamortized Costs in Schedule PCD-3 that reduces the embedded cost of long-term debt by including the effects of pre-issuance hedge gains or losses, embedded option receipts or payments, and swap termination gains or losses.

By reducing the embedded cost of long-term debt by those effects, the Company passes the benefits of those effects on to ratepayers. However, DOE recognizes that the historical approach taken by the Commission would exclude those effects. As a result,

[12] This is the regulatory weighted-average cost of capital discussed earlier because it is the weighted-average of the *before-tax* cost of debt and the after-tax cost of equity in contrast to the ATWACC, which is based on the weighted average of the after-tax costs of debt and equity.

DEO has understated the embedded cost of long-term debt relative to the approach indicated by the Standard Filing Requirements.

Q29. Has the Commission addressed that approach in prior DEO rate cases?

A29. No. The Company did not include such adjustments in prior applications. As a result, the proposed adjustment has not been before the Commission in previous Dominion rate cases.

Q30. Do you have any other comments on Schedules PCD-3 or PCD-4?

A30. Yes. After submitting the Application, the Company noted that the Other Related Unamortized Cost adjustment for the debt issue noted on line 52 was incorrect. Appendix F to my testimony includes updated PDC Schedules with the data corrected.

In addition to the PCD-3 information, a sign error was noted on Schedule PCD-4, which nominally adjusted the embedded cost of preferred stock. However, the weighted cost for that component of capital was unaffected due to the small portion of the overall capital structure that is comprised of preferred stock. Nonetheless, the updated Schedule D-4 included in Appendix F also incorporates the correction of that error.

III. COST OF CAPITAL METHODOLOGY

Q31. How is this section of your testimony organized?

A31. As noted in Section II, I estimate the cost of capital using a sample of comparable risk companies. This section first outlines the steps involved in selecting the benchmark sample, in determining the market-value capital structures, and in estimating the sample companies' costs of debt. It then turns to the procedures for estimating the cost of equity and describes the two cost of equity estimation methodologies used in this testimony, the DCF method and the risk positioning approach. These are the foundations of my cost of capital calculations which I present in the following section and which I use to derive a recommended cost of equity for DEO at the regulatory capital structure.

A. Sample Selection

Q32. What is the goal of the sample selection process?

A32. The goal of the sample selection process is to select companies with comparable business risk to the regulated company. The overall cost of capital for a part of a company depends on the risk of the business in which the part is engaged, not on the overall risk of the parent company on a consolidated basis. According to financial theory, the overall risk of a diversified company equals the market-value-weighted average of the risks of its components.

Estimating the cost of capital for the Company's regulated natural gas distribution assets is the subject of this proceeding. The ideal sample would be a number of publicly traded "pure play" companies that distribute natural gas and have a requirement to serve as providers of last resort (PoLR). "Pure Play" is an investment term referring to companies with operations only in one line of business. Publicly traded firms, firms whose shares are freely traded on stock exchanges, are ideal because the best way to infer the cost of capital is to examine evidence from capital markets on companies in the given line of business.

In this case, a sample of companies whose operations are concentrated solely in the regulated distribution portion of the natural gas industry would be ideal. So, I start with the universe of natural gas distribution utility companies covered by *Value Line*. This resulted in an initial group of 23 companies, to which I added Vectren Corporation because it is often viewed as a natural gas LDC. Companies were first eliminated if their operating regions were outside of the continental USA. I then applied my standard selection criteria to narrow the sample to those companies likely to have reliable cost of equity estimates. This resulted in a benchmark sample of ten companies. Financial characteristics of the sample companies are outlined in Table 1 below. Additional details on the sample selection process are discussed below and in Appendix B.

B. CAPITAL STRUCTURE & THE COST OF DEBT

1. Market-Value Capital Structure

Q33. What capital structure information do you require?

A33. For reasons discussed in Appendix E, explicit evaluation of the market-value capital structures of the sample companies is vital for a correct interpretation of the market evidence on the return on equity. This requires estimates of the market values of common equity, preferred equity and debt, and the current market costs of preferred equity and debt.

Q34. Please describe how you calculate the market values of common equity, preferred equity and debt.

A34. I estimate the capital structure for each sample company by estimating the market values of common equity, preferred equity and debt from the most recent publicly available data. The details are in Appendix B.

Briefly, the market value of common equity is the price per share times the number of shares outstanding. For the risk positioning approach, I use the last five trading days of each year to calculate the market value of equity for the year. I then calculate the average capital structure over the corresponding five-year period used to estimate the "beta" risk measures for the sample companies.[13] This procedure matches the estimated beta to the degree of financial risk present during its estimation period. In the DCF analyses, I use the average closing stock price over the 15 trading days ending on the day that the earnings growth rate forecasts are obtained from Bloomberg.[14]

The market value of debt is estimated at its book value adjusted by the difference between the "estimated fair (market) Value" and the "carrying cost" of long-term debt reported in each company's 10-K.[15] The market value of preferred stock for the samples

[13] *Value Line* uses five years of historical data to estimate its forecasted betas.

[14] Forecasts were obtained on June 11, 2007 for all companies in the sample.

[15] The book value of debt from Bloomberg includes all interest-bearing financial obligations that are not current and includes capitalized leases and mandatory redeemable preferred and trust preferred securities in

is set equal to its book value because the percent of preferred stock in the capital structures of the sample companies is relatively small compared to the debt and common equity components.

2. Market Costs of Debt and Preferred Equity

Q35. How do you estimate the current market cost of debt?

A35. The market cost of debt for each company is set equal to the yield on an index of public utility bonds that have the same credit rating, and the yield is reported by Bloomberg's for an index of public utility company bonds with the same S&P rating. The DCF analyses use the current credit rating whereas the risk positioning analyses use the current yield of a utility bond that corresponds to the five-year average debt rating of each company so as to match consistently the horizon of information used by *Value Line* to estimate company's beta.

Q36. How do you estimate the market cost of preferred equity?

A36. For each company with preferred stock, the cost of preferred equity for each company is set equal to the yield on an index of preferred stock as reported in the Mergent Bond Record[16] corresponding to the S&P rating of that company's debt.

3. Risk-Free Interest Rate Forecast

Q37. What is the risk-free rate?

A37. The risk-free rate is the interest rate that can be earned with certainty. A common measure of this rate is the yield on the government's Treasury bills and bonds. This rate is usually significantly below the rate which other borrowers pay for debt.

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accordance with FASB 150 effective June 2003. See Bloomberg definition of long-term debt for additional detail.

[16] Published monthly, *Mergent's Bond Record* offers a comprehensive review of over 68,000 bond issues including coverage of corporate, government, municipal, industrial development/environmental control revenue and international bonds, plus structured finance and equipment trust issues, medium-term notes, convertible issues, preferred stocks and commercial paper issues.

Q38. How do you obtain the forecasts of the risk-free interest rates over the period the utility rates set here are to be in effect?

A38. I obtain these forecast rates using data provided by Bloomberg. In particular, I use the reported government debt yields from the "constant maturity series". This information is displayed in Panels A and B of Table No. MJV-9.

Q39. What values do you use for the short-term and long-term risk-free interest rates?

A39. I use a value of 4.1 percent for the short-term risk-free interest rate and a value of 5.1 percent for the long-term risk-free interest rate as the benchmark risk-free interest rates in the equity risk premium analyses. The short-term interest rate forecast is constructed by using historical yield curve data to find the long-run average implied maturity term premia on government securities, and combining these with recent yield curve data. Details of their calculation can be found in the Workpapers to Table No. MJV-9.

C. COST OF EQUITY METHODS

Q40. How do you estimate the cost of equity for your sample companies?

A40. Recall the definition of the cost of capital from the outset of my testimony: the expected rate of return in capital markets on alternative investments of equivalent risk. My cost of capital estimation procedures address three key points implied by the definition:

1. Since the cost of capital is an expected rate of return, it cannot be directly observed; it must be inferred from available evidence.

2. Since the cost of capital is determined in capital markets (e.g., the New York Stock Exchange), data from capital markets provide the best evidence from which to infer it.

3. Since the cost of capital depends on the return offered by alternative investments of equivalent risk, measures of the risks that matter in capital markets are part of the evidence that needs to be examined.

Q41. How does the above definition help in cost of capital estimation?

A41. The definition of the cost of capital recognizes a tradeoff between risk and expected return, plotted above in Figure 1, the security market line. Cost of capital estimation methods take one of two approaches: (1) they try to identify a comparable-risk sample of companies and to estimate the cost of capital directly; or (2) they establish the location of the security market line and estimate the relative risk of the security, which jointly determine the cost of capital. In terms of Figure 1, the first approach focuses directly on the vertical axis, while the second focuses both on the security's position on the horizontal axis and on the position of the security market line.

The first type of approach is more direct, but ignores the wealth of information available on securities not thought to be of precisely comparable risk. The "discounted cash flow" or "DCF" model is an example. The second type of approach, sometimes known as "equity risk premium approach," requires an extra step, but as a result can make use of information on all securities, not just a very limited subset. The Capital Asset Pricing Model ("CAPM") is an example. While both approaches can work equally well if conditions are right, one may be preferable to the other under a given set of circumstances. In particular, approaches that rely on the entire security market line (e.g., the risk positioning model) are less sensitive to deviations from the assumptions that underlie the model, all else equal. In this proceeding, I examine sample evidence from both the DCF and risk positioning models.

1. The Risk Positioning Approach

Q42. Please explain the risk positioning method.

A42. The risk positioning method estimates the cost of equity as the sum of a current interest rate and a company specific risk premium. It is therefore sometimes also known as the "risk premium" approach. This approach may sometimes be applied informally. For example, an analyst or commission may check the spread between interest rates and what is believed to be a reasonable estimate of the cost of capital at one time, and then apply that spread to changed interest rates to get a new estimate of the cost of capital at another time.

More formal applications of the risk positioning approach take full advantage of the security market line depicted in Figure 1: they use information on all securities to identify the security market line and derive the cost of capital for the individual security based on that security's relative risk. This reliance on the entire security market line makes the method less vulnerable to the kinds of problems that arise for the DCF method, which relies on one stock at a time. The risk positioning approach is widely used and underlies most of the current research published in academic journals on the nature, determinants and magnitude of the cost of capital.

Section I of Appendix C to this testimony provides more detail on the principles that underlie the risk positioning approach. Section II of Appendix C provides the details of the risk positioning approach empirical estimates I obtain.

Q43. How are the "more formal" applications of risk positioning approach implemented?

A43. The first step is to specify the current values of the parameters that determine the security market line. The second is to determine the security's or investment's relative risk. The third is to specify exactly how the parameters combine to produce the security market line, so the company's cost of capital can be calculated based on its relative risk. All of these elements and how they relate are usefully formulated in the framework of the CAPM.

a) The Capital Asset Pricing Model

Q44. Please start with the CAPM, by describing the model.

A44. As noted above, the modern models of capital market equilibrium express the cost of equity as the sum of a risk-free rate and a market risk premium. The CAPM is the longest-standing and most widely used of these theories. The CAPM states that the cost of capital for an investment, *s*, (e.g., a particular common stock) is given by the following equation:

$$k_s = r_f + \beta_s \times MRP \qquad (2)$$

where k_s is the cost of capital for investment s; r_f is the risk-free rate, β_s is the beta risk measure for the investment s; and *MRP* is the market risk premium.

The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities do. It says that the security market line starts at the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 1, equals the risk-free interest rate). It further says that the risk premium over the risk-free rate equals the product of beta and the risk premium on a value-weighted portfolio of all investments, which by definition has average risk.

b) The Empirical Capital Asset Pricing Model

Q45. What other equity risk premium model do you use?

A45. Empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premia than predicted by the CAPM and high-beta stocks tend to have lower risk premia than predicted. A number of variations on the original CAPM theory have been proposed to explain this finding, but this finding can also be used to estimate the cost of capital directly, using beta to measure relative risk without simultaneously relying on the CAPM.

The second model makes use of these empirical findings. It estimates the cost of capital with the equation, where α is the "alpha" adjustment of the risk-return line, a constant,

$$k_s = r_f + \alpha + \beta_s \times (MRP - \alpha) \tag{3}$$

and the other symbols are defined as above. I label this model the Empirical Capital Asset Pricing Model, or "ECAPM." The alpha adjustment has the effect of increasing the intercept but reducing the slope of the security market line in Figure 1, which results in a security market line that more closely matches the results of empirical tests.

Q46. Why is it appropriate for you to use the empirical CAPM?

A46. Although the CAPM is still the most widely used cost of capital estimation model, it has not been completely satisfactory as an empirical model; however, its short-comings are directly addressed by the ECAPM. The ECAPM recognizes the consistent empirical observation that the CAPM underestimates (overestimates) the cost of capital for low (high) beta stocks. In other words, the ECAPM is based on the recognition that the actual slope of the risk-return tradeoff is flatter than predicted and the intercept higher based upon repeated empirical tests of the CAPM. The alpha parameter (α) in the ECAPM adjusts for this fact. The difference between the CAPM and the type of relationship identified in the empirical studies is depicted in Figure 2.

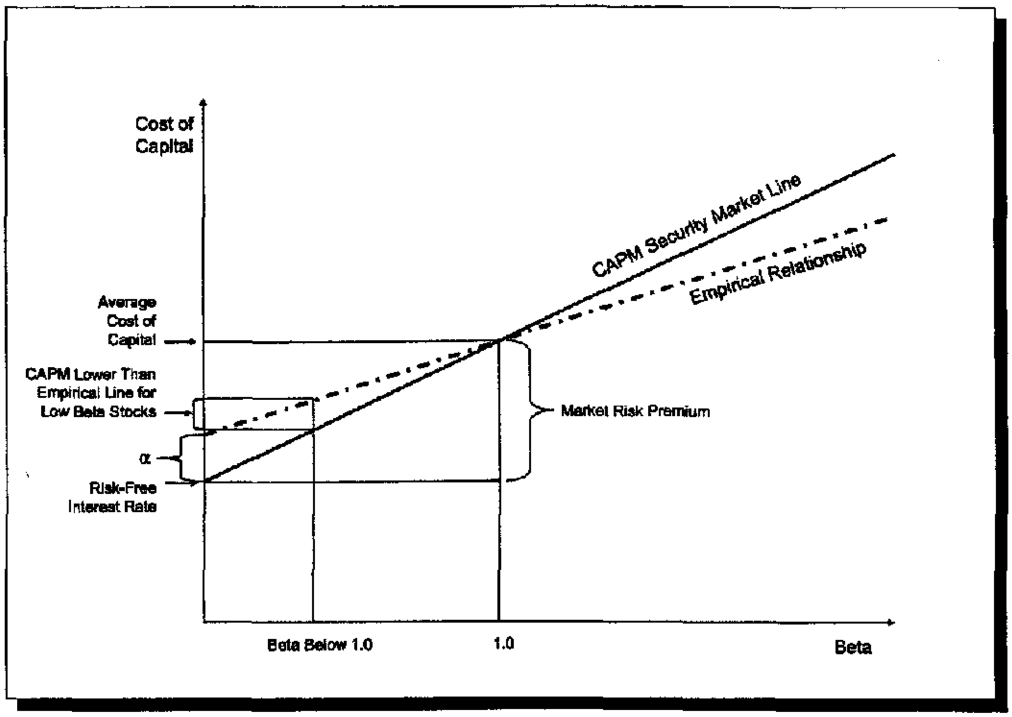

Figure 2: The Empirical Security Market Line

Research supports values for α of one to seven percent when using a short-term interest rate. I use baseline values of α of 2 percent for the short-term risk-free rate and 0.5 percent for the long-term risk-free rate. I also conduct sensitivity tests for different values of α. For the short-term risk-free rate I use values for α of 1, 2 and 3 percent. These α values are lower than would be justified by the magnitude of the correction revealed in the tests of the CAPM. For the long-term risk-free rate, the corresponding α values are 0, 0.5 and 1.5 percent. The use of a long-term risk-free rate incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the security market line has a higher intercept and a flatter slope than the short-term risk-free version which has been extensively tested. Thus, I do not need to make the same degree of refinement when I use the long-term risk-free rate. Please see Table No. MJV-

C1 in Appendix C for a summary of the empirical evidence on the size of the required adjustment necessary to better match the results of the empirical tests.

2. Discounted Cash Flow Method

Q47. Please describe the discounted cash flow approach.

A47. The DCF model takes the first approach to cost of capital estimation, i.e., to attempt to estimate the cost of capital in one step. The method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_T}{(1+k)^T} \tag{4}$$

where "P" is the market price of the stock; "D_t" is the dividend cash flow expected at the end of period t (i.e., subscript period 1, 2, 3 or T in the equation); "k" is the cost of capital; and "T" is the last period in which a dividend cash flow is to be received. The formula just says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received.

Very often, when the DCF is applied in regulatory proceedings, very strong (i.e., unrealistic) assumptions are used that yield a simplification of the standard formula, which then can be rearranged to estimate the cost of capital. Specifically, it is assumed that investors expect a dividend stream that will grow *forever* at a steady rate, and if so, the market price of the stock will be given by a very simple formula,

$$P = \frac{D_1}{(k-g)} \tag{5}$$

where "D_1" is the dividend expected at the end of the first period, "g" is the perpetual growth rate, and "P" and "k" are the market price and the cost of capital, as before. Equation (5) is a simplified version of equation (4) that can be solved to yield the well known "DCF formula" for the cost of capital:

$$\begin{aligned} k &= \frac{D_1}{P} + g \\ &= \frac{D_0 \times (1+g)}{P} + g \end{aligned} \tag{6}$$

where "D_0" is the current dividend, which investors expect to increase at rate g by the end of the next period, and the other symbols are defined as before. Equation (6) says that if equation (5) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future (forever constant) growth rate of dividends. I refer to this as the simple DCF model. Of course, the "simple" model is simple because it relies on very strong (i.e., very unrealistic) assumptions.

Q48. Are there other versions of the DCF models besides the "simple" one?

A48. Yes. The constant growth rate DCF model requires that dividends and earnings grow at the same rate for companies that earn their cost of capital on average.[17] It is inconsistent with the theory on which the model is based to have different growth rates in earnings and dividends over the period when growth is assumed to be constant. If the growth in dividends and earnings were expected to vary over some number of years before settling down into a constant growth period, then it would be appropriate to estimate a multistage DCF model. In the multistage model, earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period. A difference between forecasted dividend and earnings rates therefore is a signal that the facts do not fit the assumptions of the simple DCF model.

So, I consider a variant of the DCF model that relies on slightly less strong assumptions in that it allows for varying dividend growth rates in the near term before assuming a perpetual growth rate beginning in year eleven. I use the forecast growth of GDP as the forecast of the long-term growth rate, i.e. year eleven on. This is a "multistage" variant

[17] Why must the two growth rates be equal in a steady-growth DCF model? Think of earnings as divided between reinvestment, which funds future growth, and dividends. If dividends grow faster than earnings, there is less investment and slower growth each year. Sooner or later dividends will equal earnings. At that point, growth is zero because nothing is being reinvested (dividends are constant). If dividends grow slower than earnings, each year a bigger fraction of earnings are reinvested. That makes for ever faster growth. Both scenarios contradict the steady-growth assumption. So if you observe a company with different

of the DCF method. The DCF models are described in detail in Section I.A of Appendix D. (Section II of Appendix D provides the details of my empirical DCF results.)

Q49. What are the merits of the DCF approach?

A49. The DCF approach is conceptually sound if its assumptions are met, but can run into difficulty in practice because those assumptions are so strong[18], and hence so unlikely to correspond to reality. Dividends, earnings and prices are unlikely to grow at a constant rate literally forever. Two conditions are also well known to be necessary for the DCF approach to yield a reliable estimate of the cost of capital: the variant of the present value formula that is used must actually match the variations in investor expectations for the growth of dividends, and the growth rate(s) used in that formula must match current investor expectations. Less frequently noted conditions may also create problems (see Appendix D for details).

Q50. Is estimating the "right" dividend growth rate the most difficult part for the implementation of the DCF approach?

A50. Yes. Finding the right growth rate(s) is the usual "hard part" of a DCF application. The original approach to estimation of *g* relied on average historical growth rates in observable variables, such as dividends or earnings, or on the "sustainable growth" approach, which estimates *g* as the average book rate of return times the fraction of earnings retained within the firm. The use of historical growth rates versus the use of analysts' estimates is frequently the source of heated debated in regulatory proceedings, but it is highly unlikely that these historical averages over periods with widely varying rates of inflation and costs of capital will equal current growth rate expectations. As discussed above, this is particularly true for the natural gas industry at present because of the changes the industry is undergoing as a result of the highly volatile price of gas, the possible imposition new environmental and safety regulations and the emphasis on conservation and demand reduction. The increase in the numbers of mergers and

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expectations for dividend and earnings growth, you know the company's stock price and its dividend growth forecast are inconsistent with the assumptions of the steady-growth DCF model.

[18] In this context "strong" means that the assumption is unlikely to match reality and that it also has a substantial impact on the model's results.

acquisition in the industry adds an additional concern for the applicability of the model to the industry at this time. In addition, the electric industry is a major source of demand for natural gas, and that industry is also undergoing a period of great uncertainty regarding the ultimate structure of the industry. Similar environmental and conservation pressures are affecting the electric industry and the resulting uncertainty of the demand for electricity will have a ripple effect on the natural gas industry. This is not a description of the stable conditions necessary for the reliable implementation of the DCF model.

IV. DEO'S COST OF CAPITAL

A. THE COMPANY'S OPERATIONS AND RISKS

Q51. Please describe the Company's operations in Ohio.

A51. As explained in the testimony of Company witness Jeffrey Murphy, DEO serves approximately 1.2 million customers in over 400 communities in northeastern, southeastern and western Ohio using its over 19,000 miles of pipelines and related distribution, transmission, storage and gathering assets.

B. SAMPLE SELECTION

Q52. How did you select your sample of natural gas LDCs?

A52. The goal was to create a sample of companies whose primary business is as a regulated natural gas LDC with business risk generally similar to that of DEO's operations in Ohio. I considered the universe of 23 companies classified by the *Value Line Investment Survey Plus* as natural gas LDCs, and added Vectren Corporation to my sample because it is often viewed as a natural gas LDC.[19] Vectren is a highly regulated company involved in both gas and electric distribution activities, but more of its regulated assets are invested in the gas distribution operations.[20] This company is also covered by *Value Line*, but is

[19] The 24 companies are from Value Line Investment Survey Plus, June 11, 2007.

[20] Vectren Utility Holdings, Inc.'s 2006 10-K reveals that about 57 percent of its assets are regulated natural gas distribution assets and 37 percent are regulated electric assets. Because it has a substantial amount of regulated electric utility operations, I exclude it from the sub-sample of companies I consider to be the most

classified as an Electric Utility due to its regulated electric operations.[21] I required that the sample companies have a high percentage of assets devoted to the regulated natural gas distribution line of business. I then eliminated companies by applying additional selection criteria designed to remove companies with unique circumstances which may bias the cost of capital estimates.

Specifically, I eliminated all companies whose S&P bond rating as reported by Bloomberg was not investment grade, i.e., less than BBB- or which were not rated. To guard against measurement bias caused by "thin trading," I also restricted the sample to companies with total operating revenues greater than $300 million in 2006 as reported by Bloomberg.[22] Companies that had a large merger during the period January 2004 to June 2007 (i.e., just over the past three years) were also generally removed from the sample, although two companies which would otherwise not survive the process were included since their primary M&A activity occurred in 2004. These two companies were Atmos Energy and AGL Resources, and they were subsequently excluded from the sub-sample of companies I believe to have the fewest data issues. The screen for M&A activity was primarily done by scanning each company's news history on Bloomberg and a search of company web pages.[23] Finally, I required that the companies have historical data available from Bloomberg for the relevant period and had no dividend cuts or restatement of financial statements in the past five years, since the latter can be signs of financial distress and could cause the earnings growth rates or beta estimates to be biased.

The final sample consists of ten gas LDCs, from which I also consider a sub-sample of five companies with the fewest data issues that may affect cost of capital estimates. Table No. MJV-2 reports the estimated share of total assets for each company devoted to

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representative of the natural gas distribution line of business and to be most free of characteristics that may bias cost of equity estimates.

[21] The 23 companies are from *Value Line Investment Survey Plus*, dated June 15, 2007. Vectren's *Value Line* report is dated June 29, 2007.

[22] Data were reviewed during the second week of June 2007.

[23] Company web pages were searched in December 2003 for M&A activities during the 2001-2003 period, in July 2006 for M&A activities during the period 2004 through July 2006, and in December 2006 for the period August through December 2006.

regulated activities in 2006. Additional details on the sample selection process can be found in Appendix B. Some of the financial characteristics of the sample companies are displayed in Table 1 below.

Table 1: Financial Characteristics of the Sample Companies

Company		S&P Business Classification [1]	Revenue (2006) ($MM) [2]	Regulated Utility Assets [3]	Market Cap. (2006) ($MM) [4]	S&P Bond Rating (2007) [5]	Beta [6]	Long-Term Growth Estimate [7]
AGL Resources Inc		IE	2,621	R	3,042	A-	0.95	4.46%
Atmos Energy Corp		TD	6,152	MR	2,622	BBB	0.80	5.55%
The Laclede Group Inc	•	TD	1,998	R	753	A	0.90	4.23%
New Jersey Resources Corp		TD*	3,300	R	1,353	A	0.80	4.34%
Northwest Natural Gas Co	•	TD	1,013	R	1,161	AA-	0.75	4.75%
Piedmont Natural Gas Co	•	TD	1,925	MR	2,022	A	0.80	5.40%
South Jersey Industries Inc		TD**	931	R	981	BBB	0.70	6.47%
Southwest Gas Corp	•	IE	2,025	R	1,613	BBB-	0.85	5.46%
Vectren Corp		DI	2,042	R	2,156	A-	0.95	3.47%
WGL Holdings Inc	•	TD	2,638	MR	1,603	AA-	0.85	2.73%
Dominion Resources, Inc.		*DI*	*16,482*	*D*	*29,260*	*BBB*	*1.05*	*6.77%*
Dominion East Ohio		*TD*	*n/a*	*R*	*n/a*	*n/a*	*n/a*	*n/a*

Sources and Notes:

• Company is included in subsample (see discussion).

* Business classification is for New Jersey Natural Gas, the operating subsidiary of New Jersey Resources. A classification for New Jersey Resources Corp. is not currently available.

** Business classification is for South Jersey Gas Co., the regulated natural gas subsidiary of South Jersey Industries Inc. A classification for South Jersey Industries Inc. is not currently available.

[1] TD- Transmission and Distribution (Electric, Gas, Water); IE- Integrated Electric, Gas, and Combination Utilities; DI: Diversified Energy and Diversified Non-Energy; O- Others (Energy Merchants/Power Developers/Trading and Marketing). Source: *U.S. Utility and Power Companies, Strongest to Weakest, June 22, 2007,* published by Standard and Poor's.

[2] Bloomberg as of June 11, 2007.
[3] See Table MJV-2.
[4] See Table MJV-3, Panel's A-J.
[5] Bloomberg as of June 11, 2007.
[6] See Workpaper #1 to Table MJV-10.
[7] See Table MJV-5, column [6].

C. Potential Data Problems with the Sample

Q53. Do you have concerns regarding the data for the gas LDC sample?

A53. Possibly. Although still investment grade, Southwest Gas is at the bottom of the scale of investment grade credit ratings and has a relatively low average equity thickness over the past five years – 41.8 percent compared to 63 percent for the remaining companies. Closer investigation shows that Southwest Gas's capital structure has been shifting rapidly towards equity over the last five years, with a level of about 50 percent over the most recent two years. The Laclede Group's market capitalization of $753 million is a bit smaller than the average of the group, but with revenues of more than $1.9 billion, it is still a large company. South Jersey Industries' revenues are less than $1 billion and smaller than its market capitalization. In 2006, Piedmont Natural Gas restated some portions of its 2003-2005 financial reports. Although this can generally lead to less reliable estimates from the equity estimation models, the restatements were not caused by fraudulent activities but were due to an accounting error in the classification of hedging amounts. This type of reclassification would not be expected to change the value of the firm and prices did not show any erratic behavior in the period surrounding the announcement of this reclassification. As noted earlier, the industry has experienced a sustained level of merger and acquisition activity over the last five years that has implication for the stability of the industry and the actual cash flows that underlie the prices paid for the stocks of these companies.

Due to the concerns with some of the companies in the sample, I also report the results for a sub-sample of the gas LDC sample that consists of companies with no material data issues. Of course, the selection of such a sub-sample does not address possible biases in DCF estimates due to expected cash flows reflected in the stock price but not in the data used to estimate DCF dividends and growth rates; to the contrary, purer play companies may be more attractive targets, which would produce and even greater downward bias in their DCF calculations.

D. Relative Risk of the Sample Compared to DEO

Q54. Could you please summarize the general characteristics of the companies in the sample and those of the Company's operations in Ohio?

A54. Yes. The sample consists of ten gas LDCs with generally similar risk characteristics to those of DEO. Table 2: Risk Characteristics of the Sample companies summarizes information related to the risks of the sample and of the Company's operations in Ohio. Like the Company's operations, they all have some form of gas-cost adjustment clause, which either removes or significantly reduces their exposure to this risk. In their 10-Ks, all sample companies report that they engage in hedging activities to further reduce the risk of large changes in the price of natural gas. Eight of the ten sample companies have weather adjustment clauses, which Dominion East Ohio does not.

I have been informed by DEO that the Company is in the process of transitioning out of the merchant function of purchasing gas for its customers. In the first phase of that process, its gas cost recovery rider is being replaced by a Standard Service Offer with supply acquired through a PUCO-approved auction. However, Dominion remains the Provider of Last Resort if a supplier defaults on its obligation to provide service. As a result, while Dominion's traditional risk of under recovery of gas commodity costs will be reduced, it still faces operational and financial risks associated with that POLR obligation. Dominion also has a bad debt tracker that reduces its exposure to the inability of its customers to pay for service.

As discussed in the direct testimony of Company witness Jeffrey Murphy, Dominion still faces significant risks associated with the overall economic climate and, in particular, the economy within its service territory. Dominion receives considerable revenue from its commercial and industrial base of customers. Much of its industrial base is centered on the steel and automotive sectors, which can readily relocate production elsewhere in North America or offshore and which can face ongoing structural problems given the age of the production facilities.

Unlike many gas LDCs, DEO operates an extensive transmission system, which was affected by the provisions of the Pipeline Safety Improvement Act of 2002 that required transmission pipeline operators to develop extensive integrity management programs involving substantial O&M and capital expenses. Given the age of its system, DEO will also be heavily impacted by final rules that result from the notice of proposed rulemaking expected from the Department of Transportation's Pipeline and Hazardous Materials Safety Administration regarding distribution pipeline integrity management programs.

Recently enacted Ohio minimum gas service standards pose additional business risk to DEO as they entail increased service levels in a variety of areas ranging from call center response times to appointment scheduling and complaint handling. Even though the ompany may not have historically experienced significant problems in providing quality natural gas service, there is uncertainty imposed by the new standards.

DEO is proposing a Sales Reconciliation Rider to address conservation-related impacts on base revenues, which will decouple gas usage from the company's ability to meet its revenue requirements. It does not, however, currently have, nor has it proposed, a weather normalization clause to eliminate the effect of variations from normal weather on its earnings. Gas LDCs throughout the country have received approval to include such clauses in their rates and charges for utility service, which serves to reduce their single largest business risk. By not having such a clause, DEO is at greater risk than many other comparable LDCs in this regard.

Although DEO has begun the process of exiting the traditional regulated merchant function, that transition is far from complete, and the Commission has retained the right to place the company back in its traditional Gas Cost Recovery role if that transition does not go as well as planned. Transitions can sometimes pose more risk than maintaining the status quo. Thus, the Company's risks, which include an ongoing responsibility to act as the provider of last resort, are still substantial and may, in fact, be greater in the short-term than comparable companies that are not undergoing such a dramatic transition. If the transition turns out as expected, DEO will be less risky than the sample on average, but if the transition turns out differently than expected, the Company's business risk may be greater than, not less than, the sample on average.

Table 2: Risk Characteristics of Sample Companies

Company [1]	Fuel Cost Adjustment [2]	Weather Normalization [3]	Fuel Cost Hedging [4]	Storage Facilities [5]	S&P Business Profile [6]
AGL Resources (GA, FL, MD, NJ, TN, VA)	Yes	Yes	D	Co & Int	4
Atmos Energy (GA, KS, KY, LA, TX, MS, TN, VA)	Yes	Yes	D	Co & Int	3
Laclede Group (MO)	Yes	No	D	Co & Int	3
New Jersey Resources (NJ, NY)	Yes	Yes	D	Co & Int	2*
Northwest Natural Gas (WA, OR)	Yes	Yes	D	Co & Int	1
Piedmont Natural Gas (SC, TN, NC)	Yes	Yes	Yes	Co & Int	2
South Jersey Industries (NJ)	Yes	Incentive Program	D	Co & Int	3**
Southwest Gas (AZ, NV, CA)	Yes	Yes	Fix & Var Price	Co	4
Vectren (IN, OH)	Yes	Yes	D	Co	4
WGL Holdings (DC, VA, MD)	Yes	Yes	D	Co & Int	3
Dominion East Ohio (PA, OH, WV)	*Yes*	*No*	*D*	*Co & Int*	*7†*

Sources:
Company 10-K's, 2006.
U.S. Utility and Power Companies, Strongest to Weakest, June 22, 2007, published by Standard and Poor's.

Notes:

† S&P Business profile associated with Dominion Resources Inc. A business profile specific to Dominion's Ohio operations is not available.

[1] States of operation as reported in company 10-K's for significant operations.

[2] Yes indicates a mechanism was reported in company 10-K's, but different mechanisms exist by company and by state. If a mechanism exists, it generally allows for recovery of most prudent costs.

[3] Yes indicates a mechanism was reported in company 10-K's, but different mechanisms exist by company and by state. South Jersey Industries reports participation in a Conservation incentive program.

[4] D - Financial Derivatives Fix & Var Price - Price formulas are used to help mitigate weather risks. As reported in company 10-K's

[5] Co - Company owned Int - Storage capacity on unaffiliated interstate pipelines. Information from company 10-K's.

[6] S&P Business Profile as published on June 22, 2007 in S&P's *U.S. Utility and Power Companies, Strongest to Weakest.* **Profile is for the subsidiary New Jersey Natural Gas. **Profile is for the subsidiary South Jersey Gas Co.*

E. COST OF CAPITAL ESTIMATES

Q55. Please summarize the results of the risk positioning and DCF methodologies in estimating the average cost of capital for the benchmark sample and the implications for DEO's cost of equity?

A55. Table 3 summarizes the sample average ATWACCs derived from the risk positioning and DCF models, along with the implied cost of equity for the Company at its filed regulatory capital structure with 44.8 percent equity.

Table 3: Cost of Equity Results

Regulatory Capital Structure: *44.8% Equity / 0.8% Preferred / 54.3% Debt* *2008 Tax Rate* *35.0%*

	METHODS								
	RISK POSITIONING (Long-Term Risk-Free Rate)			RISK POSITIONING (Short-Term Risk-Free Rate)				DCF	
	CAPM	α = 0.5%	α = 1.5%	CAPM	α = 1%	α = 2%	α = 3%	Simple	Multi
[1] **Gas LDC Sample**									
Cost of Equity	12.7%	12.8%	13.0%	13.0%	13.3%	13.5%	13.7%	10.3%	10.7%
Average ATWACC	8.0%	8.1%	8.2%	8.2%	8.3%	8.4%	8.5%	6.9%	7.1%
[2] **Gas LDC Sub-sample**									
Cost of Equity	12.4%	12.5%	12.7%	12.7%	12.9%	13.2%	13.4%	9.9%	10.6%
Average ATWACC	7.9%	7.9%	8.0%	8.0%	8.1%	8.2%	8.3%	6.8%	7.1%

[3] Risk Positioning Security Market Line Parameters:				Multi-Stage DCF Parameter:	
Long-Term		*Short-Term*			
Risk-Free Rate Estimate:	5.1%	Risk-Free Rate Estimate:	4.1%	GDP Growth Estimate:	5.1%
Estimated MRP:	6.5%	Estimated MRP:	8.0%		

Sources and Notes:
Risk Positioning data is from Table No. MJV-12 and DCF data is from Table No. MJV-6.
[1],[2] See Tables 1 and 2 above for a summary of the sample and its characteristics.
[3] See Appendix C for details on the Risk Positioning parameters used in the estimates, and Appendix D for the DCF parameters and additional implementation details.

Q56. How did you determine a representative tax rate to use in your cost of capital estimation?

A56. DEO's estimated marginal income tax rate for 2008 was set the Federal corporate tax rate. Ohio does not levy a corporate income tax on regulated utilities.

Q57. How are the cost of equity estimates derived from the risk positioning approach for the benchmark sample?

A57. I derive two sets of risk-positioning estimates, one using long-term forecasts of the risk-free rate and market risk premium, and one using short-term forecasts. My long-term interest rate forecast is 5.1 percent and the corresponding estimated market risk premium is 6.5 percent. When using the short-term risk-free rate of 4.1 percent, the estimated MRP is 8.0 percent. Details on the derivation of these forecasts can be found in Appendix C.

For each estimated risk-free rate, the two risk positioning models (CAPM and ECAPM) are estimated utilizing the different values of the ECAPM parameter (0.5% and 1.5% for the long-term model and 1%, 2%, and 3% for the short-term model). I therefore obtain three long-term and four short-term estimates of each sample company's cost of equity. The results using the long-term risk-free rate are displayed in Table MJV-10, Panel A, and the results using the short-term risk-free rate are displayed in Table MJV-10, Panel B. Next, the cost of equity estimates are combined with each company's estimated cost of debt and preferred equity to calculate the company's ATWACC using each company's market value capital structure. These calculations and the resulting sample average ATWACCs are presented in Table No. MJV-11. Panels A-C rely on the cost of equity estimates from the long-term version of the model, while Panels D-G utilize the estimates from the short-term version of the model. The sample average ATWACCs and costs of equity at the Company's 44.8 percent equity capital structure for each risk positioning cost of equity estimate are displayed in Table No. MJV-12. These results are summarized in Table 3 above.

Q58. What are the DCF estimates for the benchmark sample?

A58. For each sample company, cost-of-equity estimates are calculated for the two versions of the DCF method, the simple DCF model and multistage DCF model. The DCF estimates for each company are displayed in Table No. MJV-6, Panel A (simple DCF) and Panel B (multistage DCF). The sample and sub-sample average ATWACC for each method is calculated in Table No. MJV-7, and these are used in Table No. MJV-8 to derive the return on equity at the Company's 44.8 percent equity capital structure for each estimation method (see also Table 3 above). Table 3 shows the estimated cost of equity to be 10.3 percent (simple DCF model) and 10.7 percent (multistage DCF model) for the full sample, and 9.9 percent (simple DCF) and 10.6 percent (multistage DCF) for the sub-sample. The estimates from the simple and multistage DCF models are about 2.5 to 3.0

percent lower than the estimates from risk-positioning models, for both the long-term term and short-term versions of the risk positioning model. (See Table 3: Cost of Equity Results above).

V. CONCLUSIONS

Q59. What are your conclusions from the DCF model regarding the cost of equity at the Company's 44.8 percent equity ratio?

A59. The estimated costs of equity from the simple DCF model are somewhat lower than the estimates from the multistage model, and significantly lower than any of the risk positioning model estimates. The simple DCF model relies on company-specific growth rate forecasts, but those forecasts are likely to be downward biased due to concerns about volatile natural gas prices, the series of mergers and acquisitions and potential changes in the industry. The high level of recent mergers and acquisitions is likely to have increased the market prices of the sample companies if investors anticipate potential interest in additional acquisitions in the industry, and earnings growth rates are likely to be affected following a merger as the new company consolidates its operations. Together these factors will tend to reduce the DCF estimates. In addition, the simple DCF results are unreliable because the long-run growth rate forecast drives the results, and there are no objective data on the long-run growth rate investors truly expect, or on when the industry is expected to settle down into some sort of stable-growth equilibrium. The somewhat more reliable multistage DCF estimate, after adjustment for financial risk, is about 10.7 percent which is about 40 to 80 basis points higher than the simple DCF estimates from the full sample and sub-sample, but about 200 to 230 basis points lower than the long-term risk positioning estimates. The multistage model is also affected by the same uncertainties about the industry that make the simple DCF model unreliable at this time. Although I do not put much weight upon the DCF model results in my recommended cost of equity for DEO, I believe that DCF cost capital estimates provide a useful check on the risk positioning results.

Q60. Do you have any comments regarding the results of the risk positioning models?

A60. As noted earlier, the risk positioning results are also summarized in Table 3 above. At this time, the estimated costs of equity for the long-term version of the model are lower than for the short-term version of the model. Of those results, the CAPM values deserve the least weight, because this method does not adjust for the empirical finding that the cost of capital is less sensitive to beta than predicted by the CAPM (which my testimony considers by using the ECAPM). Conversely, the ECAPM numbers deserve the most weight, because this method adjusts for the empirical findings. The cost of equity estimates using the long-term risk free rate and adjusted for a capital structure with a 44.8 percent equity ratio range from 12.7 to 13.0 percent for the full sample, and from 12.4 to 12.7 percent for the sub-sample. For the estimates based upon the short-term risk-free rate, the estimates range from 13.0 to 13.7 percent and from 12.7 to 13.4 percent for the full sample and sub-sample respectively.

The estimates based upon the short-term risk-free rate are about 30 to 70 basis points higher on average than the estimates using the long-term risk-free rate. This is partially due to the fact that the yield curve is currently less steep than it has been historically, i.e., the yield on long-term Treasury bonds only marginally exceeds the yield on short-term Treasury bills. Panel A of Table No. MJV-9 shows that 30-day Treasury bills are currently yielding an average of 4.86 percent compared to only 5.14 percent for long-term Treasury bonds. This 28 basis point difference between the yield on short-term and long-term Treasury securities is unusual. Yields on long-term Treasury bonds have averaged about 150 basis points more than the yields on 30-day Treasury bills over the last 80 years (see Workpaper #1, Panel B to Table No. MJV-9). It should be noted that although the current difference is relatively small by historical standards, it represents a movement towards normalcy from the flat and even "inverted" yield curves observed last year and early this year.

Treasury yields have exhibited a number of unusual behaviors over the past few years in response to a multitude of factors, from the uncertainty after 9/11 and a ballooning U.S. debt and trade deficit (which among other things led to the reintroduction of 30 year Treasury bonds), to a remarkable resiliency of the U.S. economy that continues to outperform expectations. The yield on short-term Treasury bills reflects the efforts by the Federal Reserve ("Fed") to prevent the rate of inflation from increasing any further, while at the same time providing enough liquidity for economic growth. If the Fed believes that inflation is not yet contained, short-term rates are likely to increase further. On the other hand, if inflation is judged to be under control, short-term rates may decline as fears of recession replace those of inflation. At this time, a great deal of additional uncertainty surrounds the policy that will be followed by the Fed in the near term as a result of a potential deterioration in credit markets and wavering confidence in future economic performance. This fear – triggered by widespread defaults in the U.S. subprime mortgage market and fueled further by negative job growth statistics– may require the Fed to maintain or even lower rates in order to avoid a large order macroeconomic downturn. On the other hand, the Fed does not want to give the appearance that it is bailing out investors who simply realized bad bets in the sub-prime market. As such, it is currently walking a fine line that could tip in either direction as events unfold. Because of this near term uncertainty, I believe that the estimates using the long-term risk-free rate are more reliable at this time.

Q61. Given the results of the two models, what is your conclusion regarding the cost of equity for DEO?

A61. The results for the somewhat more reliable multistage version of the DCF model are an average ATWACC of about 7.1 percent for both the full- and sub-sample, with a corresponding cost of equity of between 10.6 and 10.7 percent, but as noted above, I do not believe that the DCF results are reliable at this time, so I rely primarily on the results from the risk positioning model. At best, the DCF estimates serve as a floor for the estimates of the cost of equity for the Company.

I noted above, I believe that the long-term version of the risk positioning model in more reliable at this time. Focusing on the middle values in Table 3 for the results from the long-term risk positioning model (ECAPM with $\alpha = 0.5$), the average ATWACC is 8.1 percent for the full sample and 7.9 percent for the sub-sample, with corresponding costs of equity estimates of 12.8 percent and 12.5 percent respectively, but I believe that if the ongoing changes in the Company's gas supply acquisition process, the potential exit from the merchant function and the Sales Reconciliation Rider are fully implemented, the Company will be somewhat less risky than the sample on average.

Considering all of the evidence from both models, the best point estimate for the cost of equity for DEO is 12 percent. This result is about ½ percent lower than the average risk positioning results from the long-term model estimates for the sub-sample, but about 1⅓ percent higher than the multistage DCF estimates. Although I believe the DCF results to be less reliable at this time, I give some weight to the estimates in evaluating the results of the risk positioning. However, it is more correct to say that the estimates from the sample provide a range of values from a low of 11½ percent to a high of 12½ percent. As previously noted, in estimating the cost of equity I round to the nearest ¼ percent (25 basis points) because I do not believe that cost of capital estimates can be made more precisely than that.

Q62. Does this conclude your testimony?

A62. Yes

APPENDIX A

RESUMÉ

MICHAEL J. VILBERT **PRINCIPAL**

Michael Vilbert is an expert in cost of capital, financial planning and valuation who has advised clients on these matters in the context of a wide variety of investment and regulatory decisions. He received his Ph.D. in Financial Economics from the Wharton School of the University of Pennsylvania, an MBA from the University of Utah, an M.S. from the Fletcher School of Law and Diplomacy, Tufts University, and a B.S. degree from the United States Air Force Academy. He joined The Brattle Group in 1994 after a career as an Air Force officer, where he served as a fighter pilot, intelligence officer, and professor of finance at the Air Force Academy.

REPRESENTATIVE CONSULTING EXPERIENCE

- In a securities fraud case, Dr. Vilbert designed and created a model to value the private placement stock of a drug store chain as if there had been full disclosure of the actual financial condition of the firm. He analyzed key financial data and security analyst's reports regarding the future of the industry in order to recreate pro forma balance sheet and income statements under a variety of scenarios designed to establish the value of the firm.

- For pharmaceutical companies rebutting price-fixing claims in antitrust litigation, Dr. Vilbert was a member of a team which prepared a comprehensive analysis of industry profitability. The analysis replicated, tested and critiqued the major recent analyses of drug costs, risks and returns. The analyses helped develop expert witness testimony to rebut allegations of excess profits.

- For an independent electric power producer, Dr. Vilbert created a model that analyzed the reasonableness of rates and costs filed by a natural gas pipeline. The model not only duplicated the pipeline's rates, but it also allowed simulation of a variety of "what if" scenarios associated with cost recovery under alternative time patterns and joint cost allocations. Results of the analysis were adopted by the intervenor group for negotiation with the pipeline.

- For the CFO of an electric utility, Dr. Vilbert developed the valuation model used to support a stranded cost estimation filing. The case involved a conflict between two utilities over the responsibility for out-of-market costs associated with a power purchase contract between them. In addition, he advised and analyzed cost recovery mechanisms that would allow full recovery of the stranded costs while providing a rate reduction for the company's rate payers.

- Dr. Vilbert has testified as well as assisted in the preparation of testimony and the development of estimation models in numerous cost of capital cases for natural gas pipeline, water utility and electric utility clients before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions. These have spanned standard estimation techniques (e.g., Discounted Cash Flow and Risk Positioning models). He has also developed and applied more advanced models specific to the industries or lines of business in question, e.g., based on the structure and risk characteristics of cash flows, or based on multi-factor models that better characterize regulated industries.

- Dr. Vilbert has valued several large, residual oil-fired generating stations to evaluate the possible conversion to natural gas or other fuels. In these analyses, the expected pre- and post-conversion station values were computed using a range of market electricity and fuel cost conditions.

- For a major western electric utility, Dr. Vilbert helped prepare testimony that analyzed the prudence of QF contract enforcement. The testimony demonstrated that the utility had not been compensated in its allowed cost of capital for major disallowances stemming from QF contract management.

- Dr. Vilbert analyzed the economic need for a major natural gas pipeline expansion to the Midwest. This involved evaluating forecasts of natural gas use in various regions of the United States and the effect of additional supplies on the pattern of natural gas pipeline use. The analysis was used to justify the expansion before the FERC and the National Energy Board of Canada.

- For a Public Utility Commission in the Northeast, Dr. Vilbert analyzed the auction of an electric utilities purchase power agreements to determine whether the outcome of the auction was in the ratepayers' interest. The work involved the analysis of the auction procedures as well as the benefits to ratepayers of transferring risk of the PPA payments to the buyer.

- Dr. Vilbert led a team tasked to determine whether bridge tolls were "just and reasonable" for a non-profit port authority. Determination of the cost of service for the authority required estimation of the value of the authority's assets using the trended original cost methodology as well as evaluation of the operations and maintenance budgets. Investment costs, bridge traffic information and inflation indices covering a 75 year period were utilized to estimate the value of four bridges and a passenger transit line valued in excess of $1 billion.

- Dr. Vilbert helped a recently privatized railroad in Brazil develop an estimate of its revenue requirements, including a determination of the railroad's cost of capital. He also helped evaluate alternative rate structures designed to provide economic incentives to shippers as well as to the railroad for improved service. This involved the explanation and analysis of the contribution margin of numerous shipper products, improved cost analysis and evaluation of bottlenecks in the system.

- For a utility in the Southeast, Dr. Vilbert quantified the company's stranded costs under several legislative electric restructuring scenarios. This involved the evaluation of all of the company's fossil and nuclear generating units, its contracts with Qualifying Facilities and the prudence of those QF contracts. He provided analysis concerning the impact of securitizing the company's stranded costs as a means of reducing the cost to the rate payers and several alternative designs for recovering stranded costs.

- For a recently privatized electric utility in Australia, Dr. Vilbert evaluated the proposed regulatory scheme of the Australian Competition and Consumer Commission for the company's electric transmission system. The evaluation highlighted the elements of the proposed regulation which would impose uncompensated asymmetric risks on the company and the need to either eliminate the asymmetry in risk or provide additional compensation so that the company could expect to earn its cost of capital.

- For an electric utility in the Southwest, Dr. Vilbert helped design and create a model to estimate the stranded costs of the company's portfolio of Qualifying Facilities and Power Purchase contracts. This exercise was complicated by the many variations in the provisions of the contracts that required modeling in order to capture the effect of changes in either the performance of the plants or in the estimated market price of electricity.

- Dr. Vilbert helped prepare the testimony responding to a FERC request for further comments on the appropriate return on equity for electric transmission facilities. In addition, Dr. Vilbert was a member of the team that made a presentation to the FERC staff on the expected risks of the unbundled electric transmission line of business.

- Dr. Vilbert and Mr. Frank C. Graves, also of The Brattle Group, prepared testimony evaluating an innovative Canadian stranded cost recovery procedure involving the auctioning of the output of the province's electric generation plants instead of the plants themselves. The evaluation required the analysis of the terms and conditions of the long-term contracts specifying the revenue requirements of the plants for their entire forecasted remaining economic life and required an estimate of the cost of capital for the plant owners under this new stranded cost recovery concept.

- Dr. Vilbert served as the neutral arbitrator for the valuation of a petroleum products tanker. The valuation required analysis of the Jones Act tanker market and the supply and demand balance of the available U.S. constructed tanker fleet.

PRESENTATIONS

"Utility Distribution Cost of Capital," *EEI Electric Rates Advanced Course*, Bloomington, IN, 2002, 2003.

"Issues for Cost of Capital Estimation," with Bente Villadsen, *Edison Electric Institute Cost of Capital Conference*, Chicago, IL, February 2004.

"Not Your Father's Rate of Return Methodology," *Utility Commissioners/Wall Street Dialogue*, NY, May 2004.

"Current Issues in Cost of Capital," *EEI Electric Rates Advanced Course*, Madison, WI, July 2004.

"Cost of Capital Estimation: Issues and Answers," *MidAmerican Regulatory Finance Conference*, Des Moines, IA, April 7, 2005.

"Cost of Capital - Explaining to the Commission - Different ROEs for Different Parts of the Business," *EEI Economic Regulation & Competition Analysts Meeting*, May 2, 2005.

"Current Issues in Cost of Capital," with Bente Villadsen, *EEI Electric Rates Advanced Course*, Madison, WI, 2005.

"Current Issues in Estimating the Cost of Capital," *EEI Electric Rates Advanced Course*, Madison, WI, 2006.

"Revisiting the Development of Proxy Groups and Relative Risk Analysis," Society of Utility and Regulatory Financial Analysts: 39th Financial Forum, April 2007.

ARTICLES

"Flaws in the Proposed IRS Rule to Reinstate Amortization of Deferred Tax Balances Associated with Generation Assets Reorganized in Industry Restructuring," by Frank C. Graves and Michael J. Vilbert, white paper for *Edison Electric Institute* (EEI) to the IRS, July 25, 2003.

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," by A. Lawrence Kolbe, Michael J. Vilbert, Bente Villadsen and The Brattle Group, *Edison Electric Institute*, April 2005.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," by A. Lawrence Kolbe, Michael J. Vilbert and Bente Villadsen, *Public Utilities Fortnightly*, August 2005.

"Understanding Debt Imputation Issues," by Michael J. Vilbert, Bente Villadsen and Joseph B. Wharton, *Edison Electric Institute*, forthcoming August 2007.

TESTIMONY

Direct and rebuttal testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation in the matter of an application for approval of its 1999 and 2000 generation tariff, transmission tariff, and distribution revenue requirement, October 1998.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Central Maine Power in Docket No. ER00-982-000, December 1999.

Direct testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation for approval of its 2001 transmission tariff, May 2000.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Mississippi River Transmission Corporation in Docket No. RP01-292-000, March 2001.

Written evidence, rebuttal, reply and further reply before the National Energy Board in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part I and Part IV of the *National Energy Board Act*, Order AO-1-RH-4-2001, May 2001, Nov. 2001, Feb. 2002.

Written evidence before the Public Utility Board on behalf of Newfoundland & Labrador Hydro - Rate Hearings, October 2001.

Direct testimony (with Bill Lindsay) before the Federal Energy Regulatory Commission on behalf of DTE East China, LLC in Docket No. ER02-1599-000, April 2002.

Direct and rebuttal reports before the Arbitration Panel in the arbitration of stranded costs for the City of Casselberry, FL, Case No. 00-CA-1107-16-L, July 2002.

Direct reports before the Arbitration Board for Petroleum products trade in the Arbitration of the Military Sealift Command vs. Household Commercial Financial Services, fair value of sale of the Darnell, October 2002.

Direct testimony and hearing before the Arbitration Panel in the arbitration of stranded costs for the City of Winter Park, FL, In the Circuit Court of the Ninth Judicial Circuit in and for Orange County, FL, Case No. C1-01-4558-39, December 2002.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Florida Power Corporation, dba Progress Energy Florida, Inc. in Docket No. SC03-___-000, March 2003.

Direct report before the Arbitration Panel in the arbitration of stranded costs for the Town of Belleair, FL, Case No. 000-6487-C1-007, April 2003.

Direct and rebuttal reports before the Alberta Energy and Utilities Board in the matter of the Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, and the Regulations under it; in the matter of the Gas Utilities Act, R.S.A. 2000, c. G-5, and the Regulations under it; in the matter of the Public utilities Board Act, R.S.A. 2000, c. P-45, as amended, and the Regulations under it; and in the matter of Alberta Energy and Utilities Generic Cost of Capital Hearing, Proceeding No. 1271597, July 2003, November 2003.

Written evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. N–7, as amended, (Act) and the Regulations made under it; and in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part IV of the *National Energy Board Act*, for approval of Mainline Tolls for 2004, RH-2-2004, January 2004.

Direct and rebuttal testimony before the Public Service Commission of West Virginia, on Cost of Capital for West Virginia-American Water Company, Case No 04-0373-W-42T, May 2004.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission, on Energy Allocation of Debt Cost for Incremental Shipping Rates for Edison Mission Energy, Docket No. RP04-274-000, December 2004 and March 2005.

Direct testimony before the Arizona Corporation Commission, Cost of Capital for Paradise Valley Water Company, a subsidiary of Arizona-American Water Company, Docket No. WS-01303A-05, May 2005.

Written evidence before the Ontario Energy Board, Cost of Capital for Union Gas Limited, Inc., Docket No. EB-2005-0520, January 2006.

Direct and rebuttal testimony before the Pennsylvania Public Utility Commission, Return on Equity for Metropolitan Edison Company, Docket No. R-00061366 and Pennsylvania Electric Company, Docket No. R-00061367, April 2006 and August 2006.

Expert report in the United States Tax Court, Docket No. 21309-05, 34th Street Partners, DH Petersburg Investment, LLC and Mid-Atlantic Finance, Partners Other than the Tax Matters Partner, Petitioner, v. Commissioner of Internal Revenue, Respondent, July 28, 2006.

Direct and supplemental testimony before the Federal Energy Regulatory Commission, Docket No. ER06-427-003, on behalf of Mystic Development, LLC on the Cost of Capital for Mystic 8 and 9 Generating Plants Operating Under an Reliability Must Run Contract, August 2006 and September 2006.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER07-46-000, on behalf of Northwestern Corporation on the Cost of Capital for Transmission Assets, October 2006.

Direct and rebuttal testimony before the Tennessee Regulatory Authority, Case No. 06-00290, on behalf of Tennessee American Water Company, on the Cost of Capital, November, 2006 and April 2007.

Direct testimony before the Public Service Commission of Wisconsin, Docket No. _____, on behalf of Wisconsin Energy Corporation, on the Cost of Capital for Wisconsin Electric Power Company and Wisconsin Gas LLC, May 2007.

Rebuttal testimony before the California Public Utilities Commission, Docket No. A. 07-01-036-39, on behalf of California-American Water Company, on the Cost of Capital, May 2007.

Direct testimony before the Public Utilities Commission of the State of South Dakota, Docket No. NG-07-013, on behalf of NorthWestern Corporation, on the Cost of Capital for NorthWestern Energy Company's natural gas operations in South Dakota, June 2007.

Direct testimony before the Public Utilities Commission of Ohio, Case No. 07-551-EL-AIR, Case No. 07-552-EL-ATA, Case No. 07-553-EL-AAM, and Case No. 07-554-EL-UNC, on behalf of Ohio Edison Company, The Toledo Edison Company, and The Cleveland Electric Illuminating Company, on the cost of capital for the FirstEnergy Company's Ohio electric distribution utilities, June 2007.

Direct testimony before the State Corporation Commission of Virginia on behalf of Virginia Electric and Power Company, on the cost of capital for its southwest coal plant, July 2007.

APPENDIX B

SELECTING THE BENCHMARK SAMPLE AND USE OF MARKET VALUES

I. SAMPLE SELECTION AND THE SAMPLE'S CHARACTERISTICS B-1

II. MARKET VALUE CAPITAL STRUCTURE, COSTS OF DEBT & COSTS OF PREFERRED EQUITY B-4

I. SAMPLE SELECTION AND THE SAMPLE'S CHARACTERISTICS

Q1. How do you select your gas LDC benchmark sample?

A1. To select this sample, I started with the universe of publicly traded natural gas distribution utilities covered by *Value Line Investment Survey Plus*. This resulted in an initial group of 23 companies, to which I added Vectren Corporation because it is often viewed as a natural gas LDC (by Bloomberg, for example). Vectren is involved in both gas and electric distribution activities, but more of its regulated assets are invested in the gas distribution operations.[1] This company is also covered by *Value Line*, but is classified as an Electric Utility due to its regulated electric operations.[2] I then eliminated companies by applying additional selection criteria designed to remove companies with unique circumstances which may bias the cost of capital estimates. The final sample consists of ten gas LDCs, from which I also consider a sub-sample of four companies with the fewest reliability concerns. Table No. MJV-2 reports the estimated range for share of total assets for each company devoted to regulated activities in 2006.

Q2. What are the other selection criteria you applied?

A2. Companies were first eliminated if their operating regions were outside of the continental USA. I then applied my standard selection criteria to narrow the sample to those companies likely to have reliable cost of equity estimates. Specifically, I eliminated all companies whose S&P bond rating as reported by Bloomberg was not investment grade, i.e., less than BBB-, or which were not rated. To guard against measurement bias caused by "thin trading," I also restricted the sample to companies with total operating revenues greater than $300 million (USD) in 2006 as reported by Bloomberg.[3] Companies that

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1 The 24 companies are from *Value Line Investment Survey Plus*, reviewed June 11, 2007.

2 Vectren Utility Holdings, Inc.'s 2006 10-K reveals that about 57 percent of its assets are regulated natural gas distribution assets and 37 percent are regulated electric assets. Because it has a substantial amount of regulated electric activity, I exclude it from the sub-sample of companies I consider to be the most representative of the natural gas distribution line of business and to be most free of characteristics that may bias cost of equity estimates.

3 Data were reviewed during the second week of June 2007.

had a large merger during the period January 2004 to June 2007 (i.e., just over the past three years) were also generally removed from the sample, although two companies which would otherwise not survive the process were included since their primary M&A activity occurred in 2004. These two companies were Atmos Energy and AGL Resources, and they were subsequently excluded from a sub-sample of cleanest companies I also considered as part of my analysis. The screen for M&A activity was primarily done by scanning each company's news history on Bloomberg and a search of company web pages.[4]

Finally, I required that the companies have historical data available from Bloomberg for the relevant period and had no dividend cuts or restatement of financial statements in the past five years, since the latter can be signs of financial distress.

Q3. Please elaborate on how companies were eliminated from your sample.

A3. Five companies were eliminated immediately because they had a less than investment grade bond rating or no bond rating whatsoever. Three more companies -- Cascade Natural Gas Corp, Keyspan Corp, and Southern Union Co – were eliminated for excessive M&A over the past three years.[5] Nicor Inc. was eliminated because it restated earnings for 1999-2001 and because it settled regulatory compliance issues with the Federal Energy Regulatory Commission ("FERC") in 2003.[6] At the time of the restatement, Nicor's price dropped about 50 percent and issues related to the restatement remained unresolved until recently. UGI Corp. was removed because it primarily sells propane, which is not regulated, and four final companies – Chesapeake Utilities Corp, Energy West Inc, EnergySouth Inc, and RGC Resources Inc – were eliminated for low revenues.

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[4] Company web pages were searched in December 2003 for M&A activities during the 2001-2003 period, in July 2006 for M&A activities during the period 2004 through July 2006, and in December 2006 for the period August through December 2006.

[5] Keyspan additionally had recent dividend cuts.

[6] Nicor announced on October 29, 2002 that its earnings for 1999-2001 would be revised downwards by $15-35 million. March 4, 2003, Nicor released its restated earnings for 1999-2001 along with 2002 earnings.

Q4. Are there any issues with the remaining companies in your sample?

A4. Perhaps. Several companies in the sample engage in natural gas marketing activities. Given the turmoil of the energy trading markets, the companies' cost of capital estimates may be more volatile than those of more stable companies. Also, although it is characterized as investment grade, Southwest Gas is at the bottom of the scale of investment grade credit ratings and has a relatively low average equity thickness over the past five years – 42 percent compared to over sixty percent for the remaining companies. Closer investigation shows that Southwest Gas's capital structure has been shifting rapidly towards equity over the last five years, with a level of about 50 percent over the most recent two years. These factors suggest a potential reliability problem for estimates of this company's cost of capital at this time. The Laclede Group and South Jersey Industries Inc have lower than average market caps (within the full sample), but with revenues of more than $1.9 billion and $900 million, respectively, they are still large companies. In 2006, Piedmont Natural Gas restated some portions of its 2003-2005 financial reports. Although this can generally lead to less reliable estimates from the equity estimation models, the restatements were not caused by fraudulent activities but were due to an accounting error in the classification of hedging amounts. This type of reclassification would not be expected to change the value of the firm and prices did not show any erratic behavior in the period surrounding the announcement of this reclassification. A potential concern for the DCF estimates is that the industry has experienced a sustained level of M&A activity over the last five years, which has implications discussed in the body of my testimony and in Appendix D for the reliable application of the DCF model. Due to the concerns with the sample, I also report the results for a sub-sample of the gas LDC sample that consists of companies with no material data issues.

Q5. What companies are in the subsample?

A5. The subsample consists of Laclede Group, Northwest Natural Gas, Piedmont Natural Gas, Southwest Gas, and WGL Holdings. Vectren was eliminated because of its mix of both regulated natural gas and regulated electric operations. Atmos Energy and AGL

Resources were eliminated because of concerns about M&A activities in 2004, and South Jersey Industries was eliminated from the sub-sample because of the accounting restatements. All remaining companies fall into the "Regulated" category and as a group have an average S&P business profile lower (i.e., less risky) than Dominion's overall profile.

II. MARKET VALUE CAPITAL STRUCTURE, COSTS OF DEBT & COSTS OF PREFERRED EQUITY

Q6. What capital structure information do you require?

A6. For reasons discussed in my direct testimony and explained in detail in Appendix E, explicit evaluation of the market-value capital structures of the sample companies versus the capital structure used for rate making is vital for a correct interpretation of the market evidence. This requires estimates of the market values of common and preferred equity and debt, and the *current market costs of preferred equity and debt.*

Q7. How do you calculate the market-value capital structures of the sample companies?

A7. I estimate the capital structure for each company by estimating the market values of common equity, preferred equity and debt from publicly available data. The calculations are in Panels A to J of Table No. MJV-3.

The market value of equity is straightforward: the price per share times the number of shares outstanding. The market value of preferred is set equal to its book value because the portion of the capital structure financed with preferred equity is generally small. The market value of debt is estimated at the book value of debt reported by Bloomberg plus or minus the difference in the estimated fair (market) value and book value of long-term debt as reported in the companies' 10-Ks or annual reports.[7]

[7] See Panels A through J in Table No. MJV-3 for details. The adjustment relies on the difference between the companies' self-reported fair value of long-term debt and the carrying value of the same line items. This information was obtained from the sample companies' annual reports.

For purposes of assessing financial risk to common shareholders, I add an adjustment for short-term debt to the debt portion of the capital structure. This adjustment is used only for those companies whose short-term (current) liabilities exceed their short-term (current) assets. I add an amount equal to the minimum of the difference between short-term liabilities and short-term assets or the amount of short-term debt. The reason for this adjustment is to recognize that when current liabilities exceed current assets, a portion of the companies long-term assets are being financed, in effect, by short-term debt.

The market value capital structure is calculated to be consistent with the time period over which the cost of capital is estimated for the sample. The capital structure is determined over the historical period over which the relevant risk positioning parameters were determined and as of the date analysts provide forward looking growth forecasts. Therefore, Table No. MJV-3 reports the market value capital structure at year end for the years ending 2002 – 2006, and as of the first quarter in 2007. The output of these tables is the market equity-to-value, debt-to-value, and preferred equity-to-value ratios. The overall cost of capital calculation for the risk positioning estimates samples rely on the average of the market value capital structure computed for the years 2002 through 2006 as shown in Table No. MJV-4. The results in columns [1]-[3] are used in the DCF model calculations, while columns [4]-[6] are for the risk positioning models.

Q8. How do you estimate the current market cost of preferred equity?

A8. For companies with preferred equity, the cost of preferred equity for each company was set equal to the yield on an index of preferred stock as reported in the Mergent Bond Record corresponding to the S&P rating of that company's debt. The yields from Mergent were as of May 2007. In general, the average amount of preferred equity in the sample companies' capital structures is very small and frequently zero. No company has more than two percent preferred on average.[8]

[8] Dominion Resources, Inc. holds 0.8 percent preferred equity in its capital structure.

Q9. How do you estimate the current market cost of debt?

A9. The market cost of debt for each company in the DCF analysis is the current yield reported by Bloomberg for a public utility company bond corresponding to the sample company's current debt rating as classified by S&P. The risk positioning analysis, on the other hand, uses the current yield of a utility bond that corresponds to the five-year average debt rating of each company so as to match consistently the horizon of information used by *Value Line* to estimate company betas. The current S&P debt ratings were obtained from Bloomberg.

Bloomberg reports that as of June 11, 2007, the average yield on A-rated Public Utility bonds was 6.23 percent, and 6.43 percent on average for BBB-rated Public Utility bonds.[9] (See Panel C of Workpaper #1 to Table No. MJV-11 for the yields on utility bonds and preferred stock by credit rating.) As discussed in the main body of the Testimony, calculation of the after-tax cost of debt uses the projected marginal tax rate of 35 percent.

[9] All companies in the sample are either BBB, AA, or A. The yield on AA-rated utility bonds is calculated as the yield on A-rated utility bonds minus ½ times the spread between the yield on BBB and A rated utility bonds.

APPENDIX C

RISK POSITIONING METHODOLOGY AND EMPIRICAL RESULTS

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Q1. What is the purpose of this appendix?

A1. This appendix reviews the principles behind the risk positioning methodologies, describes the estimation of the parameters used in the models, and details the cost of capital estimates obtained from these methodologies. This appendix intentionally repeats portions of my direct testimony, because I want the reader to be able to have a full discussion of the issues addressed here, rather than having to continually turn back to the corresponding section of the testimony.

I. EQUITY RISK PREMIUM METHODOLOGY

Q2. How is this section of the appendix organized?

A2. It first reviews the basic nature of the equity risk premium approach. It then discusses the individual components of the model: the benchmark risk premium, the relative risk of the company or line of business in question, the appropriate interest rate, and the combination of these elements in a particular equity risk premium model.

A. THE BASIC EQUITY RISK PREMIUM MODEL

Q3. How does the equity risk premium model work?

A3. The equity risk premium approach estimates the cost of equity as the sum of a current interest rate and a risk premium. (It therefore is sometimes also known as the "risk premium" or the "risk positioning" approach.)

This approach may sometimes be applied informally. For example, an analyst or a commission may check the spread between interest rates and what is believed to be a reasonable estimate of the cost of capital at one time, and then apply that spread to changed interest rates to get a new estimate of the cost of capital at another time.

More formal applications of equity risk premium method implement the second approach to cost of capital estimation. They use information on all securities to identify the security market line (Figure 1 in the body of the testimony) and derive the cost of capital for the individual security based on that security's relative risk. This equity risk premium approach is widely used and underlies most of the current scholarly research on the nature, determinants and magnitude of the cost of capital.

Q4. How are "more formal applications" put into practice?

A4. The essential benchmarks that determine the security market line are the risk-free interest rate and the premium that a security of average risk commands over the risk-free rate. This premium is commonly referred to as the "market risk premium" ("MRP"), i.e., the excess of the expected return on the average common stock over the risk-free interest rate. In the equity risk premium approach the risk-free interest rate and MRP are common to all securities. A security-specific measure of relative risk (beta) is estimated separately and combined with the MRP to obtain the company-specific risk premium.

In principle, there may be more than one factor affecting the expected stock return, each with its own security-specific measure of relative risk and its own benchmark risk premium. For example, the "arbitrage pricing theory" and other "multi-factor" models have been proposed in the academic literature. These models estimate the cost of capital as the sum of a risk-free rate and several security-specific risk premia. However, none of these alternative models has emerged in practice as "the" improvement to use instead of the original, single-factor model. I use the traditional single-factor model in this testimony.

Accordingly, the required elements in my formal equity risk premium approach are the market risk premium, an objective measure of relative risk, the risk-free rate that corresponds to the measure of the market risk premium, and a specific method to combine these elements into an estimate of the cost of capital.

B. MARKET RISK PREMIUM

Q5. Why is a risk premium necessary?

A5. Experience (e.g., the U.S. market's October Crash of 1987) demonstrates that shareholders, even well diversified shareholders, are exposed to enormous risks. By investing in stocks instead of risk-free Government bills, investors subject themselves not only to the risk of earning a return well below those they expected in any year but also to the risk that they might lose much of their initial capital. This is why investors demand a risk premium.

I estimate two versions of the Capital Asset Pricing Model ("CAPM"). The first version measures the market risk premium as the risk premium of average risk common stocks over the long-term risk-free rate. The second version measures the risk premium relative to a short-term risk-free rate, which is the usual measure of the "market risk premium" used in capital market theories.

Q6. Please discuss some of the issues involved in selecting the appropriate MRP?

A6. To determine the cost of capital in a regulatory proceeding, the MRP should be used with a forecast of the same interest rate used to calculate the MRP (i.e., the short-term Treasury bill rate or the long-term Government rate). For example, it would be inconsistent to utilize a short-term risk-free with an estimate of the MRP derived from comparisons to long-term interest rates. In addition, the appropriate measure of the MRP should be based upon the arithmetic mean not the geometric mean return.[1] The arithmetic mean is the simple average while the geometric mean is the compound rate of return between two periods.

Q7. How do you estimate the MRP?

A7. There is presently little consensus on "best practice" for estimating the MRP, which does not mean that each approach is equally valid. For example, the latest edition of the

[1] See, for example, Morningstar, Stocks, Bonds, Bills, and Inflation: Valuation Edition 2007 Yearbook, pp. 75-77.

leading graduate textbook in corporate finance, after recommending use of the arithmetic average realized excess return on the market for many years (which for a while was noticeably over 9 percent), now reviews the current state of the research and expresses the view that the a range between 5 to 8 percent is reasonable for the U.S.[2,3]

My written testimony considers both the historical evidence and the results of scholarly studies of the factors that affect the risk premium for average-risk stocks in order to estimate the benchmark risk premium investors currently expect. I consider the historical difference in returns between the Standard and Poor's 500 Index ("S&P 500") and the risk-free rate, recent academic literature on the MRP and the results of recent surveys to estimate the market risk premium.

Q8. Please summarize the recent literature on the MRP and the conclusions you draw from it?

A8. Some recent research based upon U.S. data challenges the conventional wisdom of using the arithmetic average historical excess returns to estimate the MRP. However, after reviewing the issues in the debate, I remain skeptical for several reasons that the market risk premium has declined in the U.S. as much as is claimed in some of the literature.

First, despite eye-catching claims like "equity risk premium as low as three percent,"[4] and "the death of the risk premium,"[5] not all recent research arrives at the same conclusion. In his presidential address to the American Finance Association in 2001, Professor Constantinides seeks to estimate the unconditional equity premium based on

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[2] Richard A. Brealey, Stewart C. Myers, and Franklin Allen, *Principles of Corporate Finance*, McGraw-Hill, 8th edition, 2006, pp. 151-154.

[3] In past editions, the authors expressed the view that they are "most comfortable" with values toward the upper end of that range, but this language does not appear in the 8th edition. Although Professor Myers still holds this view, this language and other sections were dropped to accommodate a request to reduce the length of the text.

[4] Claus, J. and J. Thomas, (2001), "Equity Risk Premium as Low as Three Percent: Evidence from Analysts' Earnings Forecasts for Domestic and International Stocks," *Journal of Finance* 56:1629-1666.

[5] Arnott, R. and R. Ryan, (2001), "The Death of the Risk Premium," *Journal of Portfolio Management* 27(3):61-84.

average historical stock returns.[6] (Note that this address was based upon evidence just before the major fall in market value.) He adjusts the average returns downward by the change in price-earnings ratio because he assumes no change in valuations in an unconditional state. His estimates for 1926 to 2000 and 1951 to 2000 are 8.0 percent and 6.0 percent, respectively, over the 3-month T-bill rate. In another published study in 2001, Professors Harris and Marston use the DCF method to estimate the market risk premium for the U.S. stocks.[7] Using analysts' forecasts to proxy for investors' expectation, they conclude that over the period 1982-1998 the MRP over the *long-term* risk-free rate is 7.14 percent. As yet another example, the paper by Drs. Ibbotson and Chen (2003) adopts a supply side approach to estimate the forward looking long-term sustainable equity returns and equity risk premium based upon economic fundamentals. Their equity risk premium over the *long-term* risk-free rate is estimated to be 3.97 percent in geometric terms and 5.90 percent on an arithmetic basis. They conclude their paper by stating that their estimate of the equity risk premium is "far closer to the historical premium than being zero or negative."[8]

Second, Professor Ivo Welch surveyed a large group of financial economists in 1998 and 1999. The average of the estimated MRP was 7.1 percent in Prof. Welch's first survey and 6.7 percent in his second survey which was based on a smaller number of individuals. However, a more recent survey[9] by Prof. Welch reported only a 5.5 percent MRP.[10] In characterizing these results Prof. Welch notes that "[T]he equity premium consensus

[6] Constantinides, G.M. (2002), "Rational Asset Prices," *Journal of Finance* 57:1567-1591.

[7] Robert S. Harris and Felicia C. Marston, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance* 11 (1) 6-16, 2001.

[8] Ibbotson, R. and P. Chen (2003), "Stock Market Returns in the Long Run: Participating in the Real Economy," *Financial Analyst Journal*, 59(1):88-98. Cited figures are on p. 97.

[9] Ivo Welch (2000), "Views of Financial Economists on the Equity Premium and on Professional Controversies," *Journal of Business*, 73(4):501-537. The cited figures are in Table 2, p. 514.

[10] Ivo Welch (2001), "The Equity Premium Consensus Forecast Revisited," School of Management at Yale University working paper. The cited figure is in Table 2.

forecast of finance and economics professors seems to have dropped during the last 2 to 3 years, a period with low realized equity premia."[11]

The above quotation from Prof. Welch emphasizes the caution that must attend survey data even from knowledgeable survey participants: the outcome is likely to change quickly with changing market circumstances. Regulatory commissions should not, in my opinion, attempt to keep pace with such rapidly changing opinions.

Third, some of the evidence for negative or close to zero market risk premium simply does not make sense. Despite the relatively high valuation levels, stock returns remain much more volatile than Treasury bond returns. I am not aware of any empirical or theoretical evidence showing that investors would rationally hold equities and not expect to earn a positive risk premium for bearing their higher risk.

Fourth, I am unaware of a convincing theory for why the future MRP should have substantially declined. At the height of the stock market bubble in the U.S., many claimed that the only way to justify the high stock prices would be if the MRP had declined dramatically,[12] but this argument was heard less frequently after the market declined substantially from its tech bubble high. All else equal, a high valuation ratio such as price-earnings ratio implies a low required rate of return, hence a low MRP. However, there is considerable debate about whether the high level of stock prices (despite the burst of the internet bubble from its high in the summer of 2000) represents the transition to a new economy or is simply an "irrational exuberance," which cannot be sustained for the long term. If the former case is true, then the MRP may have decreased permanently. Conversely, the long-run MRP may remain the same even if expected market returns in the short-term are smaller.

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[11] *Ibid*, p. 8.

[12] See Robert D. Arnott and Peter L. Bernstein, "What Risk Premium is 'Normal'?," *Financial Analysts Journal* 58:64-85, for an example.

Another common argument for a lower expected MRP is that the U.S. experienced very remarkable growth in the 20th century that was not anticipated at the start of the century. As a result, the average realized excess return is overestimated meaning the standard method of estimating the MRP would be biased upward. However, one recent study by Profs. Jorion and Goetzmann finds, under some simplifying assumptions, that the so-called "survivorship bias" is only 29 basis points.[13] Furthermore, "[I]f investors have overestimated the equity premium over the second half of the last century, Constantinides (2002) argues that 'we now have a bigger puzzle on our hands' Why have investors systematically biased their estimates over such a long horizon?"[14]

To sum up the above, I cite two passages from Profs. Mehra and Prescott's review of the theoretical literature on equity premium puzzle:[15]

> Even if the conditional equity premium given current market conditions is small, and there appears to be general consensus that it is, this in itself does not imply that it was obvious either that the historical premium was too high or that the equity premium has diminished.
>
> In the absence of this [knowledge of the future], and based on what we currently know, we can make the following claim: over the long horizon the equity premium is likely to be similar to what it has been in the past and the returns to investment in equity will continue to substantially dominate that in T-bills for investors with a long planning horizon.

Q9. Is there other scholarly support for the conclusion?

A9. Yes. Another line of research was pursued by Steven N. Kaplan and Richard S. Ruback. They estimate the market risk premium in their article, "The Valuation of Cash Flow

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[13] Jorion, P., and W. Goetzmann (1999), "Global Stock Markets in the Twentieth Century," *Journal of Finance* 54:953-980. Dimson, Marsh, and Staunton (2003) make a similar point when they comment on the equity risk premia for 16 countries based on returns between 1900 and 2001: "While the United States and the United Kingdom have indeed performed well, compared to other markets there is no indication that they are hugely out of line." p.4.

[14] Mehra, R., and E.C. Prescott (2003), "The Equity Premium in Retrospect," in *Handbook of the Economics of Finance*, Edited by G.M. Constantinides, M. Harris and R. Stulz, Elsevier B.V, p. 926

[15] *Ibid*, p. 926.

Forecasts: An Empirical Analysis."[16] Professors Kaplan and Ruback compare published cash flow forecasts for management buyouts and leveraged recapitalization over the 1983 to 1989 period against the actual market values that resulted from these transactions. One of their results is an estimate of the market risk premium over the long-term Treasury bond yield that is based on careful analysis of actual major investment decisions, not realized market returns. Their median estimate is 7.78 percent and their mean estimate is 7.97 percent.[17] This is considerably higher than my estimate of 6.5 percent. Even if the maturity premium of Treasury bonds over Treasury bills were only 1 percent, well below the best estimate of 1.5 percent the resulting estimate of the market risk premium over Treasury bills is higher than my estimate of 8.0 percent.

Q10. In addition to the scholarly articles and survey evidence you discussed in Section I of your Direct Testimony, what other evidence do you consider to estimate the MRP?

A10. I also consider the long-run realized equity premia reported in Morningstar *SBBI Valuation Edition 2007 Yearbook*. The data provided cover the period 1926 through 2006. The results are discussed below.

Q11. What is the "long-run realized risk premium" in the U.S.?

A11. From 1926 to 2006, the full period reported, Morningstar's data show that the average premium of stocks over Treasury bills is 8.6 percent. I also examine the "post-War" period. The risk premium for 1947-2006 is 8.4 percent.[18] (I exclude 1946 because its economic statistics are heavily influenced by the War years; e.g., the end of price controls yielded an inflation rate of 18 percent. It is not really a "post-War" year, from an economic viewpoint.) These averages often change slightly when another year of data is added to the Ibbotson series. The average premium of stocks over the income returns on

[16] *Journal of Finance*, 50, September 1995, pp. 1059-1093.

[17] *Ibid*, p. 1082.

[18] Morningstar, SBBI Valuation Edition 2007 Yearbook, Appendix A.

long-term Government bonds is 7.1 percent for the 1926 to 2006 period and 7.1 for the 1947 to 2006 period.

Recently there has been a great deal of academic research on the MRP. This research has put practitioners in a dilemma: there is nothing close to a consensus about how the MRP should be estimated, but a general agreement in the academic community seems to be emerging that the old approach of using the average realized return over long periods gives too high an answer.

Q12. What is your conclusion regarding the MRP?

A12. Estimation of the MRP remains controversial. There is no consensus on its value or even how to estimate it. Given a careful review of all of the information, I estimate the risk premium for average risk stocks to be 8.0 percent over Treasury bills and 6.5 percent over long-term Government bonds.

C. RELATIVE RISK

Q13. How do you measure relative risk?

A13. The risk measure I examine is the "beta" of the stocks in question. Beta is a measure of the "systematic" risk of a stock — the extent to which a stock's value fluctuates more or less than average when the market fluctuates. It is the most commonly used measure of risk in capital market theories.

Q14. Please explain beta in more detail.

A14. The basic idea behind beta is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification. Beta is a measure of the risks that *cannot* be eliminated by diversification.

Diversification is a vital concept in the study of risk and return. (Harry Markowitz won a Nobel Prize for work showing just how important it was.) Over the long run, the rate of return on the stock market has a very high standard deviation, on the order of 15 - 20 percent per year. But many individual stocks have much higher standard deviations than this. The stock market's standard deviation is "only" about 15 - 20 percent because when stocks are combined into portfolios, some of the risk of individual stocks is eliminated by diversification. Some stocks go up when others go down, and the average portfolio return — positive or negative — is usually less extreme than that of individual stocks within it.

In the limiting case, if the returns on individual stocks were completely uncorrelated with one another, the formation of a large portfolio of such stocks would eliminate risk entirely. That is, the market's long-run standard deviation would be not 15-20 percent per year, but virtually zero.

The fact that the market's actual annual standard deviation is so large means that, in practice, the returns on stocks are correlated with one another, and to a material degree. The reason is that many factors that make a particular stock go up or down also affect other stocks. Examples include the state of the economy, the balance of trade, and inflation. Thus some risk is "non-diversifiable". Single-factor equity risk premium models derive conditions in which all of these factors can be considered simultaneously, through their impact on the market portfolio. Other models derive somewhat less restrictive conditions under which several of them might be individually relevant.

Again, the basic idea behind all of these models is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification, because there are a large number of large portfolios whose managers actively seek the best risk-reward tradeoffs available. Of course, undiversified investors would like to get a premium for bearing diversifiable risk, but they cannot.

Q15. Why not?

A15. Well-diversified investors compete away any premium rates of return for diversifiable risk. Suppose a stock were priced especially low because it had especially high diversifiable risk. Then it would seem to be a bargain to well diversified investors. For example, suppose an industry is subject to active competition, so there is a large risk of loss of market share. Investors who held a portfolio of all companies in the industry would be immune to this risk, because the loss on one company's stock would be offset by a gain on another's stock. (Of course, the competition might make the whole industry more vulnerable to the business cycle, but the issue here is the diversifiable risk of shifts in market share among firms.)

If the shares were priced especially low because of the risk of a shift in market shares, investors who could hold shares of the whole industry would snap them up. Their buying would drive up the stocks' prices until the premium rates of return for diversifiable risk were eliminated. Since all investors pay the same price, even those who are not diversified can expect no premium for bearing diversifiable risk.

Of course, substantial non–diversifiable risk remains, as the October Crash of 1987 demonstrates. Even an investor who held a portfolio of all traded stocks could not diversify against that type of risk. Sensitivity to such market–wide movements is what beta measures. That type of sensitivity, whether considered in a single- or multi-factor model, determines the risk premium in the cost of equity.

Q16. What does a particular value of beta signify?

A16. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk: it goes up or down by 10 percent on average when the market goes up or down by 10 percent. Stocks with betas above 1.0 exaggerate the swings in the market: stocks with betas of 2.0 tend to fall 20 percent when the market falls 10 percent, for example. Stocks with betas below 1.0 are less volatile than the market. A stock with a beta of 0.5 will tend to rise 5 percent when the market rises 10 percent.

Q17. How is beta measured?

A17. The usual approach to calculating beta is a statistical comparison of the sensitivity of a stock's (or a portfolio's) return to the market's return. Many investment services report betas, including Merrill Lynch's quarterly Security Risk Evaluation, Bloomberg and the *Value Line Investment Survey*. Betas are not always calculated the same way, and therefore must be used with a degree of caution, but the basic point that a high beta indicates a risky stock has long been widely accepted by both financial theorists and investment professionals.

Q18. Are there circumstances when the "usual approach to calculating beta" should not be used?

A18. There are at least two cases where the standard estimate of beta should be viewed skeptically.

First, companies in serious financial distress seem to "decouple" from their normal sensitivity to the stock market. The stock prices of financially distressed companies tend to change based more on individual news about their particular circumstances than upon overall market movements. Thus, a risky stock could have a low estimated beta if the company was in financial distress. Other circumstances that may cause a company's stock to decouple include an industry restructuring or major changes in a company's supply or output markets.

Second, similar circumstances seem to arise for companies "in play" during a merger or acquisition. Once again, the individual information about the progress of the proposed takeover is so much more important for that stock than day-to-day market fluctuations that, in practice, beta estimates for such companies seem to be too low.

Q19. How reliable is beta as a risk measure?

A19. Scholarly studies have long confirmed the importance of beta for a stock's required rate of return. It is widely regarded as the best single risk measure available. The merits of beta seemed to have been challenged by widely publicized work by Professors Eugene F. Fama and Kenneth R. French.[19] However, despite the early press reports of their work as signifying that "beta is dead," it turns out that beta is still a potentially important

[19] See for example, "The Capital Asset Pricing Model: Theory and Evidence", Eugene F. Fama and Kenneth R. French, *Journal of Economic Perspectives*, Volume 18, Summer 2004, pp. 25-46.

explanatory factor (albeit one of several) in their work. Thus, beta remains alive and well as the best single measure of relative risk.

D. INTEREST RATE FORECAST

Q20. What interest rates do your procedures require?

A20. Modern capital market theories of risk and return use the short-term risk-free rate of return as the starting benchmark. My measures of the MRP incorporate this approach, since they represent the excess of the expected return on the market over the 30-day U.S. Treasury bill rate and over the long-term U.S. Government bond rate. Accordingly, implementation of my procedures requires use of a forecast of the 30-day Treasury bill rate and the long-term Government bond rate.

E. COST OF CAPITAL MODELS

Q21. How do you combine the above components into an estimate of the cost of capital?

A21. By far the most widely used approach to estimation of the cost of capital is the "Capital Asset Pricing Model," and I do calculate CAPM estimates. However, the CAPM is only one equity risk premium approach technique, and I also use another.

Q22. Please start with the CAPM, by describing the model.

A22. As noted above, the modern models of capital market equilibrium express the cost of equity as the sum of a risk-free rate and a risk premium. The CAPM is the longest-standing and most widely used of these theories. The CAPM states that the cost of capital for investment *s* (e.g., a particular common stock) is given by the following equation:

$$k_s = r_f + \beta_s \times MRP \qquad \textbf{(C-1)}$$

where k_s is the cost of capital for investment *s*; r_f is the risk-free rate, β_s is the beta risk measure for the investment *s*; and *MRP* is the market risk premium.

The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities do. It says that the security market line starts at the risk-free interest rate (that is, that the return on a zero-risk security, the y-axis intercept in Figure 1 in the body of my testimony, equals the risk-free interest rate). Further, it says that the risk premium over the risk-free rate equals the product of beta and the risk premium on a value-weighted portfolio of all investments, which by definition has average risk.

Q23. What other equity risk premium approach model do you use?

A23. Empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premia than predicted by the CAPM and high-beta stocks tend to have lower risk premia than predicted. A number of variations on the original CAPM theory have been proposed to explain this finding. The difference between the CAPM and the type of relationship identified in the empirical studies is depicted in Figure MJV-C1.

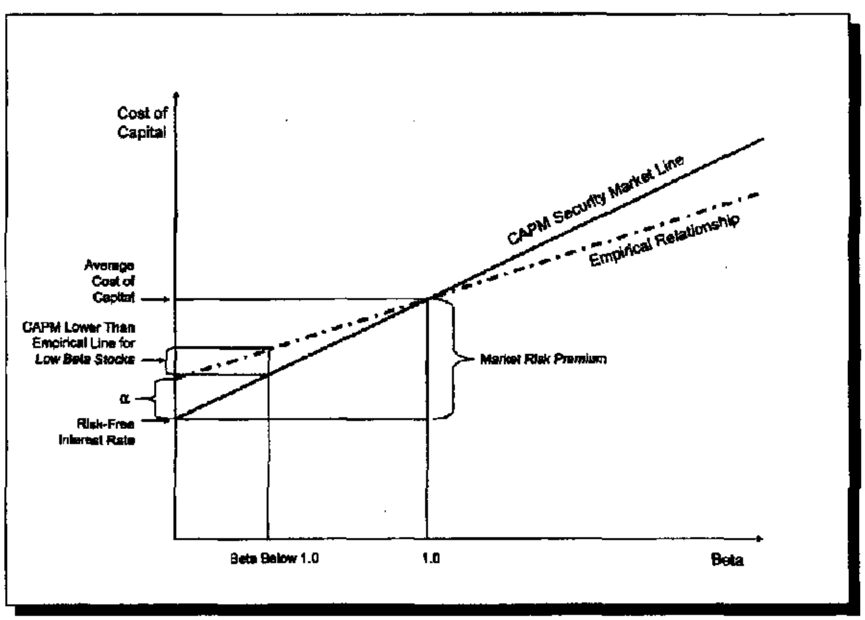

Figure MJV-C1: The Empirical Security Market Line

The second model makes use of these empirical findings. It estimates the cost of capital with the equation,

$$k_s = r_f + \alpha + \beta_s \times (MRP - \alpha) \qquad \textbf{(C-2)}$$

where α is the "alpha" of the risk-return line, a constant, and the other symbols are defined as above. I label this model the Empirical Capital Asset Pricing Model, or "ECAPM." For the short-term risk-free rate models, I set alpha equal to 1, 2, and 3 percent which are values somewhat lower than that estimated empirically. For low-beta stocks such as regulated utilities, the use of a lower value for alpha leads to a lower estimate of the cost of capital. For the long-term risk-free rate models, I set alpha equal to both 0.5 percent and 1.5 percent, but I rely more heavily on the 0.5 percent results. The use of a long-term risk-free rate incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the Security Market Line has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. Thus, it is likely that I do not need to make the same degree adjustment when I use the long-term risk-free rate. A summary of the empirical evidence on the magnitude of alpha is provided in Table No. MJV-C1 below.

II. EMPIRICAL EQUITY RISK PREMIUM RESULTS

Q24. How is this part of the appendix organized?

A24. This section presents the full details of my equity risk premium approach analyses, which are summarized in the body of my testimony. Details behind the forecasts of the short-term and the long-term risk-free interest rates are discussed. Next, the beta estimates, and the estimates of the MRP I use in the models are addressed. Finally, this section reports the CAPM and ECAPM results for the sample's costs of equity, and then describes the results of adjusting for differences between the benchmark sample and Dominion's regulated capital structure.

A. RISK-FREE INTEREST RATE FORECAST

Q25. How do you obtain the forecasts of the risk-free interest rates over the period the utility rates set here are to be in effect?

A25. I obtain these forecast rates using data provided by Bloomberg. In particular, I use their reported government debt yields from the "constant maturity series". This information is displayed in Panels A and B of Table No. MJV-9.

Q26. What values do you use for the short-term and long-term risk-free interest rates?

A26. I use a value of 4.1 percent for the short-term risk-free interest rate and a value of 5.1 percent for the long-term risk-free interest rate as the benchmark interest rates in the equity risk premium analyses. These forecasts are constructed by using historical yield curve data to find the long-run average implied term premia on government securities, and combining these with recent yield curve data. Details of their calculation can be found in the Workpapers to Table No. MJV-9.

B. BETAS AND THE MARKET RISK PREMIUM

1. Beta Estimation Procedures

Q27. How do you estimate beta?

A27. I use the beta estimates reported in the *Value Line* for the sample companies. The current *Value Line* beta estimates range from 0.70 to 0.95 for the benchmark sample (See Workpaper #1 to Table No. MJV-10).

2. Market Risk Premium Estimation

Q28. Given all of the evidence, what MRP do you use in your analysis?

A28. It is clear that market return information is volatile and difficult to interpret, but based on the collective evidence, the MRP I use for the short-term risk-free rate is 8 percent and for the long-term risk-free rate is 6.5 percent.

C. COST OF CAPITAL ESTIMATES

Q29. Based on these data, what are the values you calculate for the overall cost of capital and the corresponding cost of equity for the sample?

A29. Panels A and B of Table No. MJV-10 present the cost of equity results using the equity risk positioning methods. Panel A uses the long-term risk-free rate forecast while Panel B uses the short-term risk-free rate forecast. These returns on equity are replicated and the overall cost of capital for the various equity risk positioning methods are reported in Table No. MJV-11, Panels A to G. Panels A through C utilize the long-term risk-free rate while Panels D through G use the short-term risk free rate. Panel A reports the cost of capital estimates using the CAPM results for the long-term risk-free rate, while Panels B and C report these estimates for the ECAPM cost of equity results using ECAPM parameters of 0.5 and 1.5 percent, respectively. Panel D reports the CAPM estimates using the short-term risk free rate, while Panels E, F and G report ECAPM results using ECAPM parameters of 1, 2 and 3 respectively. In each panel, column [8] reports the overall cost of capital for each company. The last row of each panel reports the sample average.

Q30. What does the sample market data imply about the sample's cost of equity at Dominion's proposed 44.8 percent equity ratio?

A30. The sample average ATWACC from each panel of Table No. MJV-11 is reproduced in column [1] of Table No. MJV-12, which then reports the cost of equity for each of the risk positioning methods that is consistent with the sample information and Dominion's proposed capital structure. The sample average ATWACCs and corresponding costs of equity at a 44.8 percent equity ratio are also displayed in Table 3 of my testimony.

I discuss the implications of the equity risk positioning results for the sample in the main body of my testimony.

Table MJV-C1

EMPIRICAL EVIDENCE ON THE ALPHA FACTOR IN ECAPM*		
AUTHOR	RANGE OF ALPHA	PERIOD RELIED UPON
Black (1993)[1]	1% for betas 0 to 0.80	1931-1991
Black, Jensen and Scholes (1972)[2]	4.31%	1931-1965
Fama and McBeth (1972)	5.76%	1935-1968
Fama and French (1992)[3]	7.32%	1941-1990
Litzenberger and Ramaswamy (1979)[4]	5.32%	1936-1977
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 3.91%	1926-1978
Pettengill, Sundaram and Mathur (1995)[5]	4.6%	1936-1990

*The figures reported in this table are for the longest estimation period available and, when applicable, use the authors' recommended estimation technique. Many of the articles cited also estimate alpha for sub-periods and those alphas may vary.

[1]Black estimates alpha in a one step procedure rather than in an un-biased two-step procedure.

[2]Estimate a negative alpha for the subperiod 1931-39 which contain the depression years 1931-33 and 1937-39.

[3]Calculated using Ibbotson's data for the 30-day treasury yield.

[4]Relies on Lizenberger and Ramaswamy's before-tax estimation results. Comparable after-tax alpha estimate is 4.4%.

[5]Pettengill, Sundaram and Mathur rely on total returns for the period 1936 through 1990 and use 90-day treasuries. The 4.6% figure is calculated using auction averages 90-day treasuries back to 1941 as no other series were found this far back.

Sources:

Black, Fischer. 1993. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18.

Black, F., Michael C. Jensen, and Myron Scholes. 1972. The Capital Asset Pricing Model: Some Empirical Tests, from Studies in the theory of Capital Markets. In *Studies in the Theory of Capital Markets,* edited by Michael C. Jensen, 79-121. New York: Praeger.

Fama, Eugene F. and James D. MacBeth. 1972. Risk, Returns and Equilibrium: Empirical Tests. *Journal of Political Economy* 81 (3): 607-636.

Fama, Eugene F. and Kenneth R. French. 1992. The Cross-Section of Expected Stock Returns. *Journal of Finance* 47 (June): 427-465.

Litzenberger, Robert H. and Krishna Ramaswamy. 1979. The Effect of Personal Taxes and Dividends on Capital Asset Prices, Theory and Empirical Evidence. *Journal of Financial Economics* XX (June): 163-195.

Litzenberger, Robert H. and Krishna Ramaswamy and Howard Sosin. 1980. On the CAPM Approach to Estimation of a Public Utility's Cost of Equity Capital. *The Journal of Finance* 35 (2): 369-387.

Pettengill, Glenn N., Sridhar Sundaram and Ike Mathur. 1995. The Conditional Relation between Beta and Returns. *Journal of Financial and Quantitative Analysis* 30 (1): 101-116.

APPENDIX D

DISCOUNTED CASH FLOW METHODOLOGY:

DETAILED PRINCIPLES AND RESULTS

I. DISCOUNTED CASH FLOW METHODOLOGY PRINCIPLES 1

A. SIMPLE AND MULTI-STAGE DISCOUNTED CASH FLOW MODELS 1

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D. COMPANY-SPECIFIC DCF COST OF CAPITAL ESTIMATES 12

Q1. What is the purpose of this appendix?

A1. This appendix reviews the principles behind the discounted cash flow or "DCF" methodology and the details of the cost of capital estimates obtained from this methodology.

I. DISCOUNTED CASH FLOW METHODOLOGY PRINCIPLES

Q2. How is this section of the appendix organized?

A2. The first part discusses the general principles that underlie the DCF approach. The second portion describes the strengths and weaknesses of the DCF model and why it is generally less reliable for estimating the cost of capital for the sample companies at the present time than the risk positioning method discussed in Appendix C.

A. SIMPLE AND MULTI-STAGE DISCOUNTED CASH FLOW MODELS

Q3. Please summarize the DCF model.

A3. The DCF model takes the first approach to cost of capital estimation discussed with Figure 1 in Section II-A of my direct testimony. That is, it attempts to measure the cost of equity in one step. The method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_T}{(1+k)^T} \qquad \textbf{(D-1)}$$

where "P" is the market price of the stock; "D_i" is the dividend cash flow expected at the end of period i; "k" is the cost of capital; and "T" is the last period in which a dividend cash flow is to be received. The formula just says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received.

Most DCF applications go even further, and make very strong (*i.e.*, unrealistic) assumptions that yield a simplification of the standard formula, which then can be rearranged to estimate the cost of capital. Specifically, if investors expect a dividend stream that will grow forever at a steady rate, the market price of the stock will be given by a very simple formula,

$$P = \frac{D_1}{(k-g)} \qquad \textbf{(D-2)}$$

where "D_1" is the dividend expected at the end of the first period, "g" is the perpetual growth rate, and "P" and "k" are the market price and the cost of capital, as before. Equation D-2 is a simplified version of Equation D-1 that can be solved to yield the well known "DCF formula" for the cost of capital:

$$\begin{aligned} k &= \frac{D_1}{P} + g \\ &= \frac{D_0 \times (1+g)}{P} + g \end{aligned} \qquad \textbf{(D-3)}$$

where "D_0" is the current dividend, which investors expect to increase at rate g by the end of the next period, and the other symbols are defined as before. Equation D-3 says that if Equation D-2 holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. I refer to this as the simple DCF model. Of course, the "simple" model is simple because it relies on very strong (*i.e.*, very unrealistic) assumptions.

Q4. Are there other versions of the DCF models besides the "simple" one?

A4. Yes. If Equation D-2 and its underlying assumptions do not hold, sometimes other variations of the general present value formula, Equation D-1, can be used to solve for k in ways that differ from Equation D-3. For example, if there is reason to believe that investors do *not* expect a steady growth rate forever, but rather have different growth rate forecasts in the near term (e.g., over the next five or ten years as compared with subsequent periods), these forecasts can be used to specify the early dividends in

Equation D-1. Once the near-term dividends are specified, Equation D-2 can be used to specify the share price value at the end of the near-term (e.g., at the end of five or ten years), and the resulting cash flow stream can be solved for the cost of capital using Equation D-1.

More formally, the "multi-stage" DCF approach solves the following equation for k:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_T + P_{TERM}}{(1+k)^T} \qquad \textbf{(D-4)}$$

The terminal price, P_{TERM} is estimated as

$$P_{TERM} = \frac{D_{T+1}}{(k - g_{LR})} \qquad \textbf{(D-5)}$$

where T is the last of the periods in which a near term dividend forecast is made and g_{LR} is the long-run growth rate. Thus, Equation D-4 defers adoption of the very strong perpetual growth assumptions that underlie Equation D-2 — and hence the simple DCF formula, Equation D-3 — for as long as possible, and instead relies on near term knowledge to improve the estimate of k. I examine both simple and multi-stage DCF results below.

Q5. What are the merits of the DCF model?

A5. The DCF approach is conceptually sound only if its assumptions are met. In actual practice one can run into difficulty because those assumptions are so strong, and hence so unlikely to correspond to reality. Two conditions are well-known to be necessary for the DCF approach to yield a reliable estimate of the cost of capital: the variant of the present value formula, Equation D-1, that is used must actually match the variations in investor expectations for the dividend growth path; and the growth rate(s) used in that formula must match current investor expectations. Less frequently noted conditions may also create problems.

The DCF model assumes that investors expect the cost of capital to be the same in all future years. Investors may not expect the cost of capital to be the same, which can bias the DCF estimate of the cost of capital in either direction.

The DCF model only works for companies for which the standard present value formula works. The standard formula does *not* work for companies that operate in industries or markets options (*e.g.*, puts and calls on common stocks), and so it will not work for companies whose stocks behave as options do. Option-pricing effects will be important for companies in financial distress, for example, which implies the DCF model will *understate* their cost of capital, all else equal.

In recent years even the most basic DCF assumption, that the market price of a stock in the absence of growth options is given by the standard present value formula (*i.e.*, by Equation D-1 above), has been called into question by a literature on market volatility.[1] In any case, it is still too early to throw out the standard formula, if for no other reasons than that the evidence is still controversial and no one has offered a good replacement. But the evidence suggests that it must be viewed with more caution than financial analysts have traditionally applied. Simple models of stock prices may not be consistent with the available evidence on stock market volatility.

Q6. Normally DCF debates center on the right growth rate. What principles underlie that choice?

A6. Finding the right growth rate(s) is indeed the usual "hard part" of a DCF application. The original approach to estimation of g relied on average historical growth rates in

[1] See for example, Robert J. Shiller (1981), "Do Stock Prices Move Too Much to be Justified by Subsequent Changes in Dividends?," *The American Economic Review*, Vol. 71, No. 3, pp. 421-436. John Y. Campbell and Robert J. Shiller (1988), "The Dividend-Price Ratio and Expectations of Future Dividends and Discount Factors," *The Review of Financial Studies*, Vol. 1, No. 3, pp. 195-228. Lucy F. Ackert and Brian F. Smith (1993), "Stock Price Volatility, Ordinary Dividends, and Other Cash Flows to Shareholders," *Journal of Finance*, Vol. 48, No. 1, pp. 1147-1160. Eugene F. Fama and Kenneth R. French (2001), "Disappearing Dividends: Changing Firm Characteristics or Lower Propensity to Pay?," *Journal of Financial Economics*, Vol. 60, pp. 3-43. Borja Larrain and Motohiro Yogo (2005), "Does Firm Value Move Too Much to be Justified by Subsequent Changes in Cash Flow?," Federal Reserve Bank of Boston, *Working Paper*, No. 05-18.

observable variables, such as dividends or earnings, or on the "sustainable growth" approach, which estimates g as the average book rate of return times the fraction of earnings retained within the firm. But it is highly unlikely that historical averages over periods with widely varying rates of inflation, interest rates and costs of capital, such as in the relatively recent past, will equal current growth rate expectations. A better approach is to use the growth rates currently expected by investment analysts, if an adequate sample of such rates is available. If this approach is feasible and if the person estimating the cost of capital is able to select the appropriate version of the DCF formula, the DCF method should yield a reasonable estimate of the cost of capital for companies not in financial distress and without material option-pricing effects (always subject to recent concerns about the applicability of the basic present value formula to stock prices as well as issues of optimism bias). However, for the DCF approach to work, the basic stable-growth assumption must become reasonable and the underlying stable-growth rate must become determinable *within the period for which forecasts are available.*

Most cost of capital experts rely on earnings growth rate forecasts, not dividend growth rates, for several reasons. First, although the model is derived from dividend growth rates, the more fundamental parameter is earnings growth because dividends are paid from earnings. Second, analyst forecasts of dividend growth rates are generally not available, but earnings growth forecasts are. Third, a better approach than relying on historical information is to use the growth rates currently expected by investment analysts, if an adequate sample of such rates is available. Analysts' forecasts are superior to time series forecasts based upon single variable historical data as has been documented and confirmed extensively in academic research.[1] If this approach is feasible and if the person

[1]Lawrence D. Brown and Michael S. Rozeff (1978), "The Superiority of Analysts Forecasts as Measures of Expectations: Evidence from Earnings," *Journal of Finance*, Vol. XXXIII, No. 1, pp. 1-16. J. Cragg and B.G. Malkiel (1982), *Expectations and the Structure of Share Prices*, National Bureau of Economic Research, University of Chicago Press. R.S. Harris (1986), "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring Issue, pp. 58-67. J. H. Vander Weide and W. T. Carleton (1988), "Investor Growth Expectations: Analysts vs. History," *Journal of Portfolio Management*, Spring, pp. 78-82. T. Lys and S. Sohn (1990), "The Association Between Revisions of Financial Analysts Earnings Forecasts and Security Price Changes," *Journal of Accounting and Economics*, vol 13, pp. 341-363.

estimating the cost of capital is able to select the appropriate version of the DCF formula, the DCF method should yield a reasonable estimate of the cost of capital for companies not in financial distress and without material option-pricing effects. However, for the DCF approach to work, the basic stable-growth assumption must become reasonable and the underlying stable-growth rate must become determinable *within the period for which forecasts are available.*

Q7. What is the so called "optimism bias" in the earnings growth rate forecasts of security analysts and what is its effect on the DCF analysis?

A7. Optimism bias is related to the observed tendency for analysts to forecast earnings growth rates that are higher than are actually achieved. This tendency to over estimate growth rates is perhaps related to incentives faced by analysts that provide rewards not strictly based upon the accuracy of the forecasts. To the extent optimism bias is present in the analysts' earnings forecasts; the cost of capital estimates from the DCF model would be too high.

Q8. Does optimism bias mean that the DCF estimates are completely unreliable?

A8. No. The effect of optimism bias is least likely to affect DCF estimates for large, rate regulated companies in relatively stable segments of an industry. Furthermore, the magnitude of the optimism bias (if any) for regulated companies is not clear. This issue is addressed in a paper by Chan, Karceski, and Lakonishok (2003)[2] who sort companies on the basis of the size of the I/B/E/S forecasts to test the level of optimism bias. Utilities constitute 25 percent of the companies in lowest quintile, and by one measure the level of optimism bias is 4 percent. However, the 4 percent figure does not represent the complete characterization of the results in the paper. Table IX of the paper shows that the median I/B/E/S forecast for the first (lowest) quintile averages 6.0 percent. The realized "Income before Extraordinary Items" is 2.0 percent (implying a four percent

[2] L. K.C. Chan, J. Karceski, and J. Lakonishok, 2003, "The Level and Persistence of Growth Rates," *Journal of Finance* 58(2):643-684.

upward bias in I/B/E/S forecasts), but the "Portfolio Income before Extraordinary Items" is 8.0 percent (implying a two percent downward bias in I/B/E/S forecasts).

The difference between the "Income before Extraordinary Items" and "Portfolio Income before Extraordinary Items" is whether individual firms or a portfolio are used in estimating the realized returns. The first is a simple average of all firms in the quintile while the second is a market value weighted-average. Although both measures of bias have their own drawbacks according to the authors,[3] the Portfolio Income measure gives more weight to the larger firms in the quintile such as regulated utilities. In addition, the paper demonstrates that "analysts' forecasts as well as investors' valuations reflect a wide-spread belief in the investment community that many firms can achieve streaks of high growth in earnings."[4] Therefore, it is not clear how severe the problem of optimism bias may be for regulated utilities or even whether there is a problem at all.

Finally, the two-stage DCF model also adjusts for any over optimistic (or pessimistic) growth rate forecasts by substituting the long-term GDP growth rate for the 5-year growth rate forecasts of the analysts in the years beginning in year 11. I linearly trend the 5-year forecast growth rate to the GDP forecast growth rate in years 6 to 10.

Q9. What about the reforms by the National Associate of Security Dealers (NASD) that were designed to reduce the conflicts of interest and pressures brought against security analysts? Have those reforms been generally successful?

A9. Yes. The conclusion from the Joint Report by NASD and the New York Stock Exchange ("NYSE") on the reforms states

> …the SRO Rules have been effective in helping restore integrity to research by minimizing the influences of investment banking and promoting transparency of other potential conflicts of interest. Evidence

[3] Chan, Karceski, and Lakonishok, *op. cit.*, p. 675.

[4] Chan, Karceski, and Lakonishok, *op. cit.*, p. 663.

> also suggests that investors are benefiting from more balanced and accurate research to aid their investment decisions.[5]

The report does note additional reforms are advisable, but the situation is far different today than during the height of the tech bubble when analyst objectivity was clearly suspect.

B. CONCLUSIONS ABOUT DCF

Q10. Please sum up the implications of this part of the appendix.

A10. The unavoidable questions about the DCF model's strong assumptions — whether the basic present value formula works for stocks, whether option pricing effects are important for the company, whether the right variant of the basic formula has been found, and whether the true growth rate expectations have been identified — cause me to view the DCF method as *inherently* less reliable than equity risk premium approach, the other approach I use. However, because the DCF method has been widely used in the past and in other forums when the industry's economic conditions were different from today's, I submit DCF evidence in this case. DCF estimates also serve as a check on the values provided by the risk positioning approach methods.

II. EMPIRICAL DCF RESULTS

Q11. How is this part of the appendix organized?

A11. This section presents the details of my DCF analyses for the sample, which are summarized in my written testimony. The first part describes some preliminary matters, such as the calculation of market value capital structures of the sample companies and the determination of the growth rates. It then turns to the details of the DCF estimates themselves.

[5] Joint Report by NASD and NYSE on the Operation and Effectiveness of the Research Analyst Conflict of Interest Rules, December 2005, p. 44.

In particular, implementation of the simple DCF models described above requires an estimate of the current price, the dividend, and near-term and long-run growth rate forecasts. The simple DCF model relies only on a single growth rate forecast, while the multistage DCF model employs both near-term individual company forecasts and long-run GDP growth rate forecasts. The remaining parts of this section describe each of these inputs in turn.

A. Preliminary Matters

Q12. In Appendix C you discuss estimating cost of capital and implied cost of equity using the risk positioning methodology. What, if anything, is different when you use the DCF method?

A12. First, the timing of the market value capital structure calculations is different in the DCF method than in the equity risk premium method. The equity risk premium method relies on the average capital structure over the five-year period *Value Line* uses to estimate beta while the DCF approach uses only current data, so the relevant market value capital structure measure is the most recent that can be calculated. This capital structure is reported in columns [1]-[3] of Table No. MJV-4.

B. Growth Rates

Q13. What growth rates do you use?

A13. For reasons discussed above, historical growth rates are generally unreliable as forecasts of current investor expectations. I therefore use rates forecasted by security analysts.

The ideal in a DCF application would be a detailed forecast of future dividends, year by year well into the future, based on a large sample of investment analysts' expectations. I know of no source of such data. Dividends are ultimately paid from earnings, however, and earnings forecasts are available for a few years. Investors do not expect dividends to grow in lockstep with earnings, but for companies for which the DCF approach can be used reliably (*i.e.*, for relatively stable companies whose prices do not include the option-like values described previously), they do expect dividends to track earnings over the long-run. Thus, use of earnings growth rates as a proxy for expectations of dividend growth rates is a common practice.

Accordingly, the first step in my DCF analysis is to examine a sample of investment analysts' forecasted earnings growth rates. In particular, I utilize Bloomberg's BEst and *Value Line's* forecasted earnings growth.[6] The projected earnings growth rates for the sample companies are in Table No. MJV-5. Column [1] reports Bloomberg's BEst analysts' forecasts of the long-term earnings growth for the sample companies. Column [2] reports the number of analysts that provided a forecast. Columns [3] and [4] report *Value Line's* forecasted earnings per share ("EPS") value for each company for 2007 and 2010-2012 respectively. Column [5] provides *Value Line's* implied long-term growth rate forecast, and column [6] provides a weighted average growth rate for each company across the two sources. (I treat the *Value Line* forecasts as though they overlap exactly with the forecasts from Bloomberg.) These growth rates underlie my simple and multi-stage DCF analyses.

In particular, the five-year average annual growth rate is the perpetual growth rate I employ in the simple DCF model.[7] In the multi-stage model, I rely on the company-specific growth rate until 2012 and on the long-term GDP forecast for year 2018 onwards. During the years from 2013 to 2017, I assume the growth rate converges linearly towards the long-term GDP forecast.[8]

Q14. Do these growth rates correspond to the ideal you mentioned above?

A14. No, not completely. While forecasted growth rates are the quantity required in principle, the forecasts need to go far enough out into the future so that it is reasonable to believe that investors expect a stable growth path afterwards. As can be seen from Table No. MJV-5, the growth rate estimates do not support the view that investors are expecting

[6] The BEst growth rates were downloaded from Bloomberg on June 11, 2007. *Value Line* numbers are their most recent available, variously dated June 15, 2007 or June 29, 2007. (See Table No. MJV-5.)

[7] This growth rate is in column [6] of Table No. MJV-5.

[8] I use the long-term U.S. GDP growth estimate from *Blue Chip Economic Indicators* (March 10, 2007).

growth rates equal to the single perpetual growth rate assumed in the simple DCF model. For example, Vectren and WGL Holdings have growth rate estimates of 3.5 percent and 2.7 percent respectively, while South Jersey Industries Inc's estimate is 6.5 percent (see column [6], Table No. MJV-5).

It should be noted that there are at least two analyst estimates for all of the sample companies, though The Laclede Group has only two. The comparison between the average growth rate forecasts and the growth in GDP forecast indicates that these growth rates may be under-stated for some gas companies.

Q15. How well are the conditions needed for DCF reliability met at present?

A15. The requisite conditions for the sample companies are not fully met at this time. Of particular concern for this proceeding is the uncertainty about what investors truly expect the long-run outlook for the sample companies to be. The longest time period available for growth rate forecasts of which I am aware is five years. The long-run growth rate (*i.e.*, the growth rate after the energy industry settles into a steady state, which is certainly *beyond* the next five years for this industry) drives the actual results one gets with the DCF model. Unfortunately, this implies that unless the company or industry in question is stable – so there is little doubt as to the growth rate investors expect – DCF results in practice can end up being driven by the subjective judgment of the analyst who performs the work.

Such circumstances imply that a regulator may often be faced with a wide range of DCF numbers, none of which can be well grounded in objective data on true long-run growth expectations, *because no such objective data now exist*. DCF for firms or industries in flux is *inherently* subjective with regard to a parameter (the long-run growth rate) that drives the answer one gets.

C. DIVIDEND AND PRICE INPUTS

Q16. What values do you use for dividends and stock prices?

A16. Dividends are the last recorded dividend payments as reported by Bloomberg, the 1st-quarter 2007 dividend. This dividend is grown at the estimated growth rate and divided by the price described below to estimate the dividend yield for the simple and multi-stage DCF models.

For the sample calculations, stock prices are the average of the closing stock prices for the 15 trading days (approximately three weeks) ending June 11, 2007 for each company, the same date growth rate estimates were pulled from Bloomberg. I do not use a longer period to measure the price, because that would be inconsistent with the principles that underlie the DCF formula. The DCF approach assumes the stock price is the present value of future expected dividends. Stock prices six months or a year ago reflect expectations at that time, which are different from those that underlie the currently available growth forecasts. At the same time, use of an average over a brief period helps guard against a company's price on a particular day price being unduly influenced by mistaken information, differences in trading frequency, and the like.

The closing stock price is used because it is at least as good as any other measure of the day's outcome, and may be better for DCF purposes. In particular, if there were any single price during the day that would affect investors' decisions to buy or sell a stock, I would suspect that it would be each day's closing price, not the high or low during the day. The daily price changes reported in the financial pages, for example, are from close to close, not from high to high or from low to low.

D. COMPANY-SPECIFIC DCF COST OF CAPITAL ESTIMATES

Q17. What DCF estimates do these data yield?

A17. The cost of equity results for the simple and multistage DCF models are shown in Table No. MJV-6. Panel A reports the results for the simple DCF method while Panel B reports the results for the multistage DCF method using the long-term GDP growth rate as the perpetual growth rate.

Q18. What overall cost of capital estimates result from the DCF cost of equity estimates?

A18. The capital structure, DCF cost of equity, and cost of debt estimates are combined to obtain the overall after-tax weighted-average cost of capital for each sample company. These results are presented in Table No. MJV-7. Again, Panel A relies on the simple DCF cost of equity results while Panel B relies on the multistage DCF cost of equity results.

Q19. What information do you report in Table No. MJV-8?

A19. This table reports the return on equity consistent with the sample's estimated overall after-tax weighted-average cost of capital and the proposed equity thickness of 44.8 percent for Dominion. For both the simple DCF and multistage DCF methods, the sample's average ATWACC is reported in column [1]. Column [6] reports the return on equity as if the sample companies' average market value capital structure had been that currently proposed by Dominion.

Q20. What are the implications of these results?

A20. The implication of these numbers is discussed in my written testimony, along with the findings of the equity risk premium approach.

APPENDIX E

EFFECT OF DEBT ON THE COST OF EQUITY

I. AN OVERVIEW OF THE ECONOMIC LITERATURE E-1

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1. Base Case: No Taxes, No Risk to High Debt Ratios E-2
2. Corporate Tax Deduction for Interest Expense E-3
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A. DETAILS OF DIFFERENT LEVELS OF DEBT E-12

B. THE IMPACT OF INCOME AND INTEREST E-16

C. THE EFFECT OF TAXES E-19

D. COMBINED EFFECTS E-25

Q1. What is the purpose of this Appendix?

A1. In this appendix, I provide details on the effects of debt on the cost of equity. First, I summarize a fairly large body of financial research on capital structure. Second, I provide an extended example to illustrate the effect of debt on the cost of equity.

I. AN OVERVIEW OF THE ECONOMIC LITERATURE

Q2. What is the focus of the economic literature on the effects of debt?

A2. The economic literature focuses on the effects of debt on the value of a firm. The standard way to recognize one of these effects, the impact of the fact that interest expense is tax-deductible, is to discount the all-equity after-tax operating cash flows generated by a firm or an investment project at a weighted average cost of capital, typically known in textbooks as the "WACC." The textbook WACC equals the *market*-value weighted average of the cost of equity and the *after-tax*, *current* cost of debt. However, rate regulation in North America has a legacy of working with another weighted-average cost of capital, the *book*-value weighted average of the cost of equity and the *before-tax*, *embedded* cost of debt. To distinguish the concepts, I refer to the after-tax weighted-average cost of capital as ATWACC.

Q3. How is this section of the appendix organized?

A3. It starts with the tax effects of debt. It then turns to other effects of debt.

A. TAX EFFECTS

Q4. What are the key findings in the literature regarding tax effects?

A4. Three seminal papers are vital for this literature. The first assumes no taxes and risk-free debt. The second adds corporate income taxes. The third adds personal income taxes.

1. Base Case: No Taxes, No Risk to High Debt Ratios

Q5. Please start by explaining the simplest case of the effect of debt on the value of a firm.

A5. The "base case," no taxes and no costs to excessive debt, was worked out in a classic 1958 paper by Franco Modigliani and Merton Miller, two economists who eventually won Nobel Prizes in part for their body of work on the effects of debt.[1] Their 1958 paper made what is in retrospect a very simple point: if there are no taxes and no risk to the use of excessive debt, use of debt will have no effect on a company's operating cash flows (i.e., the cash flows to investors as a group, debt plus equity combined). If the operating cash flows are the same regardless of whether the company finances mostly with debt or mostly with equity, then the value of the firm cannot be affected at all by the debt ratio. In cost of capital terms, this means the overall cost of capital is constant regardless of the debt ratio, too.

In the base case, issuing debt merely divides the cash flows into two pools, one for bondholders and one for shareholders. If the divided pools have different priorities in claims on the cash flows, the risks and costs of capital will differ for each pool. But the risk and overall cost of capital of the entire firm, the sum of the two pools, is constant regardless of the debt ratio. Thus,

$$r_1^* = r_{A1} \qquad \text{(E-1a)}$$

where r^*_1 is the overall after-tax cost of capital at any particular capital structure and r_{A1} is the all-equity cost of capital for the firm. (The "1" subscripts distinguish the case where there are no taxes from subsequent equations that consider first corporate and then both corporate and personal taxes.) With no taxes and no risk to debt, the overall cost of capital does not change with capital structure.

This implies that the relationship of the overall cost of capital to the component costs of debt and equity is

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[1] Franco Modigliani and Merton H. Miller (1958), "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48, pp. 261-297.

$$r_{E1} \times \left(\frac{E}{V}\right) + r_{D1} \times \left(\frac{D}{V}\right) = r_1^* \quad \text{(E-1b)}$$

with the overall cost of capital (r^*) on the *right* side, as the *independent* variable, and the costs of equity (r_E) and debt (r_D) on the left side, as *dependent* variables determined by the overall cost of capital and by the capital structure (i.e., the shares of equity (E) and debt (D) in overall firm value (V=E+D)) that the firm happens to choose. Note that if equation (E-1a) were correct, the equation that solved it for the cost of equity would be,

$$r_{E1} = r_1^* + (r_1^* - r_D) \times \left(\frac{D}{E}\right) \quad \text{(E-1c)}$$

Note also that (D/E) gets exponentially higher in this equation as the debt-to-value ratio increases[2] i.e., the cost of equity increases exponentially with leverage.

2. Corporate Tax Deduction for Interest Expense

Q6. What happens when you add corporate taxes to the discussion?

A6. If corporate taxes exist with risk-free debt (and if only taxes at the corporate level matter, not taxes at the level of the investor's personal tax return), the initial conclusion changes. Debt at the corporate level reduces the company's tax liability by an amount equal to the marginal tax rate times interest expense. All else equal, this will add value to the company because more of the operating cash flows will end up in the hands of investors as a group. That is, if only corporate taxes mattered, interest would add cash to the firm equal to the corporate tax rate times the interest expense. This increase in cash would increase the value of the firm, all else equal. In cost of capital terms, it would reduce the overall cost of capital.

How much the value of the firm would rise and *how far* the overall cost of capital would fall would depend in part on how often the company adjusts its capital structure, but this

[2] For example, at 20-80, 50-50, and 80-20 debt-equity ratios, (D/E) equals, respectively, (20/80) = 0.25, (50/50) = 1.0, and (80/20) = 4.0. The extra 30 percent of debt going from 20-80 to 50-50 has much less impact on (D/E) [i.e., by moving it from 0.25 to 1.0] than the extra 30 percent of debt going from 50-50 to 80-20 [i.e., by moving it from 1.0 to 4.0]. Since the cost of equity equals a constant risk premium times the debt-equity ratio, the cost of equity grows ever more rapidly as you add more and more debt.

is a second-order effect in practice. (The biggest effect would be if companies could issue riskless perpetual debt, an assumption Profs. Modigliani and Miller explored in 1963, in the second seminal paper;[3] this assumption could *not* be true for a real company.) Prof. Robert A. Taggart provides a unified treatment of the main papers in this literature and shows how various cases relate to one another.[4] Perhaps the most useful set of benchmark equations for the case where only corporate taxes matter are:

$$r_2^* = r_{A2} - r_D \times t_C \times \left(\frac{D}{V}\right) \tag{E-2a}$$

$$r_2^* = r_{E2} \times \left(\frac{E}{V}\right) + r_D \times \left(\frac{D}{V}\right) \times (1 - t_C) \tag{E-2b}$$

which imply for the cost of equity,

$$r_{E2} = r_{A2} + (r_{A2} - r_D) \times \left(\frac{D}{E}\right) \tag{E-2c}$$

where the variables have the same meaning as before but the "2" subscripts indicate the case that considers corporate but not personal taxes.

Note that Equation (E-2a) implies that when only corporate taxes matter, the overall after-tax cost of capital declines steadily as more debt is added, until it reaches a minimum at 100 percent debt (i.e., when D/V = 1.0). Note also that Equation (E-2c) still implies an exponentially increasing cost of equity as more and more debt is added. In fact, except for the subscript, Equation (E-2c) looks just like Equation (E-1c).
However, whether any value is added and whether the cost of capital changes at all also depends on the effect of taxes at the personal level.

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[3] Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

[4] Robert A. Taggart, Jr. (1991), "Consistent Valuation and Cost of Capital Expressions with Corporate and Personal Taxes," *Financial Management* 20, pp. 8-20.

3. Personal Tax Burden on Interest Expense

Q7. How do personal taxes affect the results?

A7. Ultimately, the purpose of investment is to provide income for consumption, so personal taxes affect investment returns. For example, in the U.S., municipal bonds have lower interest rates than corporate bonds because their income is taxed less heavily at the personal level. In general, capital appreciation on common stocks is taxed less heavily than interest on corporate bonds because (1) taxes on unrealized capital gains are deferred until the gains are realized, and (2) the capital gains tax rate is lower. Dividends are taxed less heavily than interest, also, under current tax law.[5] The effects of personal taxes on the cost of common equity are hard to measure, however, because common equity is so risky.

Professor Miller, in his Presidential Address to the American Finance Association,[6] explored the issue of how personal taxes affect the overall cost of capital. The paper pointed out that personal tax effects could offset the effect of corporate taxes entirely.

Q8. Is it likely that the effect of personal taxes will completely neutralize the effect of corporate taxes?

A8. I do not believe so, although the likelihood of such a result would be increased if the current federal tax reductions on dividends and capital gains became permanent rather than expiring in 2010. However, personal taxes are important even if they do not make the corporate tax advantage on interest vanish entirely. Capital gains and dividend tax advantages definitely convey some personal tax advantage to equity, and even a partial personal advantage to equity reduces the corporate advantage to debt.

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[5] The current maximum personal tax rate on dividend income was extended to the end of 2010 by the President on May 17, 2006. It is uncertain whether the reduced rates on dividend income will be further extended.

[6] Merton H. Miller (1977), "Debt and Taxes," *The Journal of Finance*, 32: 261-276, the third of the seminal papers mentioned earlier.

The Taggart paper explores the case of a partial offset, also. With personal taxes, the risk-free rate on the security market line is the after-personal-tax rate, which must be equal for risk-free debt and risk-free equity.[7] Therefore, the pre-personal-tax risk-free rate for equity will generally not be equal to the pre-personal-tax risk-free rate for debt. In particular, $r_{fE} = r_{fD}\times[(1-t_D)/(1-t_E)]$, where r_{fE} and r_{fD} are the risk-free costs of equity and debt and t_E and t_D are the personal tax rates for equity and debt, respectively. In terms of the cost of debt, the Taggart paper's results imply that a formal statement of these effects can be written as:[8]

$$r_3^* = r_{A3} - r_D \times t_N \times \left(\frac{D}{V}\right) \qquad \text{(E-3a)}$$

$$= r_{E3} \times \left(\frac{E}{V}\right) + r_D \times \left(\frac{D}{V}\right) \times (1 - t_C) \qquad \text{(E-3b)}$$

which imply

$$r_{E3} = r_{A3} + \left[r_{A3} - r_D \times \left(\frac{1-t_D}{1-t_E}\right)\right] \times \left(\frac{D}{E}\right) \qquad \text{(E-3c)}$$

Suppose, for example, that $t_C = 0.35$ percent, $t_E = 7.7$ percent and $t_D = 40$ percent. Then $[(1-t_D)/(1-t_E)] = 0.65 = (1-t_C)$. That condition corresponds to Miller's 1977 paper, in which the net personal tax advantage of equity fully offsets the net corporate tax advantage of debt. Note also that in that case, $t_N = 0$.[9] Therefore, if the personal tax advantage on equity fully offsets the corporate tax advantage on debt, Equation (E-3a) confirms that the overall after-tax cost of capital is a constant.

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[7] As Prof. Taggart notes (his footnote 9), it is not necessary that a specific, risk-free equity security exist as long as one can be created synthetically, through a combination of long and short sales of traded assets. Such constructs are a common analytical tool in financial economics.

[8] The net all-tax effect of debt on the overall cost of capital, t_N, equals $\{[t_C+t_E-t_D-(t_C\times t_E)] / (1-t_E)\}$, where t_D is the personal tax rate on debt, as before. This measure of net tax effect is designed for use with the cost of debt in Equation (E-3a), which seems more useful in the present context. The Taggart paper works with a similar measure, but one which is designed for use with the cost of risk-free equity in the equivalent Taggart equation.

[9] In the above example, $t_N = \{[0.35+0.077-0.4-(0.35\times0.077)] / (1.0-0.077)\} = 0.0/0.923 = 0$.

However, it is unlikely that the personal tax advantage of equity fully offsets the corporate tax advantage of debt. If taxes were all that mattered (i.e., if there were no other costs to debt), the overall after-corporate-tax cost of capital would still fall as debt was added, just not as fast.

Finally, note that the overall after-tax cost of capital, Equation (E-3b), still uses the corporate tax rate even when personal taxes matter. Equations (E-2b) and (E-3b) both correspond to the usual formula for the ATWACC. Personal taxes affect the way the cost of equity changes with capital structure -- Equation (E-3c) -- but not the formula for the overall after-tax cost of capital given that cost of equity.

B. NON-TAX EFFECTS

Q9. Please describe the non-tax effects of Debt.

A9. If debt is truly valuable, firms should use as much as possible, and competition should drive firms in a particular industry to the same, optimal capital structure for the industry. If debt is harmful on balance, firms should avoid it. Neither picture corresponds to what we actually see. A large economic literature has evolved to try to explain why.

Part of the answer clearly is the costs of excessive debt. Here the results cannot be reduced to equations, but they are no less real for that fact. As companies add too much debt, the costs come to outweigh the benefits. Too much debt reduces or eliminates financial flexibility, which cuts the firm's ability to take advantage of unexpected opportunities or weather unexpected difficulty. Use of debt rather than internal financing may be taken as a negative signal by the market.

Even if the company is generally healthy, more debt increases the risk that the company cannot use all of the interest tax shields in a bad year. As debt continues to grow, this problem grows and others may crop up. Management begins to worry about meeting debt payments instead of making good operating decisions. Suppliers are less willing to extend trade credit, and a liquidity shortage can translate into lower operating profits.

Ultimately, the firm might have to go through the costs of bankruptcy and reorganization. Collectively, such factors are known as the costs of "financial distress."[10]

The net tax advantage to debt, if positive, is affected by costs such as a growing risk that the firm might have to bear the costs of financial distress. First, the expected present value of these costs offsets the value added by the interest tax shield. Second, since the likelihood of financial distress is greater in bad times when other investments also do poorly, the possibility of financial distress will increase the risks investors bear. These effects increase the variability of the value of the firm. Thus, firms that use too much debt can end up with a higher overall cost of capital than those that use none.

Other parts of the answer include the signals companies send to investors by the decision to issue new securities, and by the type of securities they issue. Other threads of the literature explore cases where management acts against shareholder interests, or where management attempts to "time" the market by issuing specific securities under different conditions. For present purposes, the important point is that no theory, whether based on taxes or on some completely different issue, has emerged as "the" explanation for capital structure decisions by firms. Nonetheless, despite the lack of a single "best" theory, there is a great deal of relevant empirical research.

Q10. What does that research show?

A10. The research does not support the view that debt makes a material difference in the value of the firm, at least not once a modest amount of debt is in place. If debt were truly valuable, competitive firms should use as much debt as possible short of producing financial distress, and competitive firms that use less debt ought to be less profitable. The research shows exactly the opposite.

[10] See, for example, Section 18.3 of Brealey, Myers and Allen, 2006, *Principles of Corporate Finance*, 8th Edition, McGraw-Hill/Irwin, 2006.

For example, Kester[11] found that firms in the same industry in both the U.S. and Japan do not band around a single, "optimal" capital structure, and the most profitable firms are the ones that use the *least* debt. This finding comes despite the fact that both countries at the time (unlike the U.S. currently) had fully "classical" tax systems, in which dividends are taxed fully at both the corporate and personal level. Wald[12] confirms that high profitability implies low debt ratios in France, Germany, Japan, the U.K., and the U.S. Booth *et al.* find the same result for a sample of developing nations.[13] Fama and French[14] analyze over 2000 firms for 28 years (1965-1992, inclusive) and conclude, "Our tests thus produce no indication that debt has net tax benefits."[15] A paper by Graham[16] carefully analyzes the factors that might have led a firm not to take advantage of debt. It confirms that a large proportion of firms that ought to benefit substantially from use of additional debt, including large, profitable, liquid firms, appear not to use it "enough."

This research leaves us with only three options: either (1) apparently good, profit-generating managers are making major mistakes or deliberately acting against shareholder interests, (2) the benefits of the tax deduction on debt are less than they appear, or (3) the non-tax costs to use of debt offset the potential tax benefits. Only the first of these possibilities is consistent with the view that the tax deductibility of debt conveys a material cost advantage. Moreover, if the first explanation were interpreted to mean that otherwise good managers are acting against shareholder interests, either

[11] Carl Kester (1986), "Capital and Ownership Structure: A Comparison of United States and Japanese Manufacturing Concerns," *Financial Management*, 15:5-16.

[12] John K. Wald (1999), "How Firm Characteristics Affect Capital Structure: An International Comparison," *Journal of Financial Research*, 22:161-167.

[13] Laurence Booth *et al.* (2001), "Capital Structures in Developing Countries," *The Journal of Finance* Vol. LVI, pp. 87-130, finds at p. 105 that "[o]verall, the strongest result is that profitable firms use less total debt. The strength of this result is striking ..."

[14] Eugene F. Fama and Kenneth R. French (1998), "Taxes, Financing Decisions and Firm Value," *The Journal of Finance*, 53:819-843.

[15] *Ibid.*, p. 841.

[16] John R. Graham (2000), "How Big Are the Tax Benefits of Debt," *The Journal of Finance*, 55:1901-1942.

deliberately or by mistake, it would require the additional assumption that their competitors (and potential acquirers) let them get away with it.

Q11. Are there any explanations in the financial literature for this puzzle other than stupid or self-serving managers at the most profitable firms?

A11. Yes. For example, Stewart C. Myers, a leading expert on capital structure, made it the topic of his Presidential Address to the American Finance Association.[17] The poor performance of tax-based explanations for capital structure led him to propose an entirely different mechanism, the "pecking order" hypothesis. This hypothesis holds that the net tax benefits of debt (i.e., corporate tax advantage over personal tax disadvantage) are at most of a second order of importance relative to other factors that drive actual debt decisions.[18] Similarly, Baker and Wurgler (2002)[19] observe a strong and persistent impact that fluctuations in market value have on capital structure. They argue that this impact is not consistent with other theories. The authors suggest a new capital structure theory based on market timing -- capital structure is the cumulative outcome of attempts to time the equity market.[20] In this theory, there is no optimal capital structure, so market timing financing decisions just accumulate over time into the capital structure outcome. (Of course, this theory only makes sense if investors do not recognize what managers are doing.)

[17] Stewart C. Myers (1984), "The Capital Structure Puzzle," *The Journal of Finance*, 39: 575-592. See also S. C. Myers and N. S. Majluf (1984), "Corporate Financing Decisions When Firms Have Information Investors Do Not Have," *Journal of Financial Economics* 13:187-222.

[18] See also Stewart C. Myers (1989), "Still Searching for Optimal Capital Structure," *Are the Distinctions Between Debt and Equity Disappearing?*, R.W. Kopke and E. S. Rosengren, eds., Federal Reserve Bank of Boston.

[19] Malcolm Baker and Jeffrey Wurgler (2002), "Market Timing and Capital Structure," *The Journal of Finance* 57:1-32.

[20] *Ibid.*, p. 29.

Q12. Do inter-firm differences within an industry explain the wide variations in capital structure across the firms in an industry?

A12. No. This view is contradicted by the empirical research. As mentioned before, it has long been found that the most profitable firms in an industry, i.e., those in the best position to take advantage of debt, use the least.[21] Graham (2000) carefully examines differences in firm characteristics as possible explanations for why firms use "too little" debt and concludes that such differences are *not* the explanation: firms that ought to benefit substantially from more debt by all measurable criteria, if the net tax advantage of debt is truly valuable, voluntarily do not use it.[22]

Nor does the research support the view that firms are constantly trying to adjust their capital structures to optimal levels. Additional research on the pecking order hypothesis demonstrates that firms do not tend towards a target capital structure, or at least do not do so with any regularity, and that past studies that seemed to show the contrary actually lacked the power to distinguish whether the hypothesis was true or not.[23] In the words of the Shyam-Sunder - Myers paper p. 242, "If our sample companies did have well-defined optimal debt ratios, it seems that their managers were not much interested in getting there."

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[21] For example, Kester, *op. cit.* and Wald, *op. cit.*

[22] While not contradicting Graham's finding that differences in firm characteristics do not explain capital structure differences, Nengjiu Ju, Robert Parrino, Allen M. Poteshman, and Michael S. Weisbach, "Horses and Rabbits? Trade-Off Theory and Optimal Capital Structure," *Journal of Financial and Quantitative Analysis*, June 2005, pp. 1-24, looks at the issue in a different manner. Their paper uses a dynamic rather than static model to analyze the tradeoff between the tax benefits of debt and the risk of financial distress. It finds that bankruptcy costs by themselves are enough to explain observed capital structures, once dynamic effects are considered. This means debt is not as valuable as suggested by the traditional static analysis (of the sort used by Graham).

[23] Lakshmi Shyam-Sunder and Stewart C. Myers (1999), "Testing static tradeoff against pecking order models of capital structure," *Journal of Financial Economics* 51:219-244.

II. EXPANDED EXAMPLE

Q13. What topics do you cover in this section?

A13. The discussion in my testimony did not detail the impact of different starting points for the level of debt nor did it address income earned on the investment, interest expense, or taxes. This section covers these topics. First, it discusses how the level of debt affects the cost of equity. Second, it addresses the influence of income and interest on the investment. Third, it explains the impact of taxes on capital structure decisions. The final topic covered in this section is the combined consequence of tax and non-tax effects of debt.

A. DETAILS OF DIFFERENT LEVELS OF DEBT

Q14. Why does more debt mean more risk for equity holders?

A14. Debt magnifies the variability of the equity return. As a simple example, think of an investor who takes money out of her savings and invests $100,000 in real estate. The future value of the real estate is uncertain. If the real estate market booms, she wins. If the real estate market goes down, she loses. Figure E-1 below illustrates this.

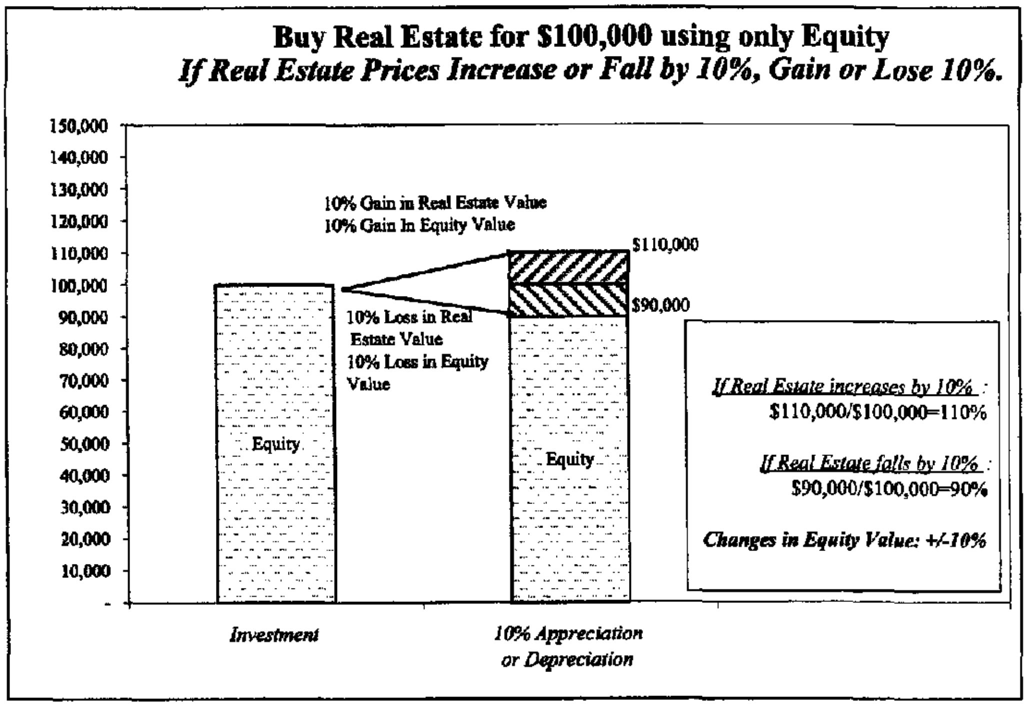

Figure E-1

In the scenario above, the investor financed her real estate purchase through 100 percent equity. Suppose instead that the investor had financed 50 percent of her real estate investment with a mortgage of $50,000. The mortgage lender does not expect to share in any benefits from increases in real estate values. Neither does the mortgage lender expect to share in any losses from falling real estate values, i.e., the investor carries the entire risk of fluctuating real estate prices. Figure E-2 illustrates this effect.

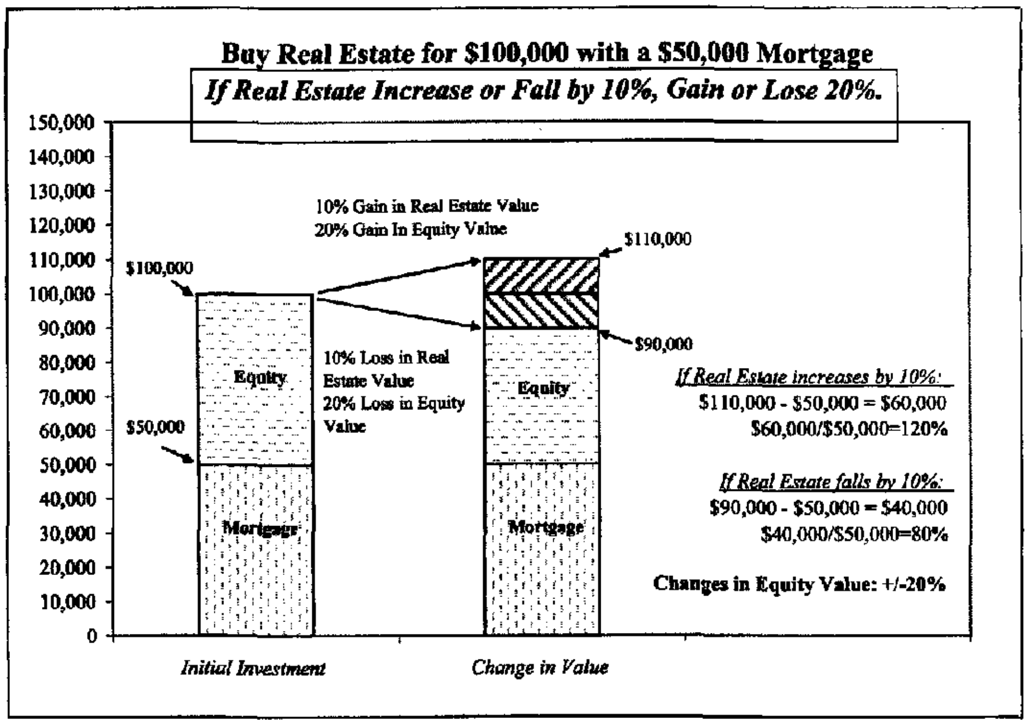

Figure E-2

In Figure E-2 where the investor financed her purchase through 50 percent equity and 50 percent debt, the variability in the investor's equity return is two times greater than that of Figure E-1. The entire fluctuation of 10 percent from rising or falling real estate prices falls on the investor's $50,000 equity investment. The lesson from the example is obvious, debt adds risk to equity.

Q15. What happens if the investor finances the real estate purchase with different proportions of debt?

A15. The equity return becomes more variable when the mortgage percentage is a greater proportion of the initial price. Table E-1 below calculates the return on equity when real estate prices increase by 10 percent when mortgages are 0 percent, 30 percent, 50 percent, and 70 percent of the initial price.

Table E-1: The Impact of Leverage on the Return on Equity

	100% Equity	70% Equity	50% Equity	30% Equity
Debt	$0	$30,000	$50,000	$70,000
Original Equity Investment	$100,000	$70,000	$50,000	$30,000
Increase in Market Value of Equity	$10,000	$10,000	$10,000	$10,000
Return on Equity Investment	10%	14.3%	20%	33.3%

Note that going from 70 percent equity down to 50 percent equity increases the return on the equity investment by 5.7 percent while going from 50 percent equity to 30 percent equity increases the return on equity by 13.3 percent. This illustrates a general point; the rate of return on equity increases more quickly at higher levels of debt than at lower levels. Investors demand a higher equity rate of return to bear more risk and debt magnifies equity's risk at an ever increasing rate. Therefore, the required equity rate of return goes up at an ever increasing rate as debt is added. This is not only basic finance theory, it is the everyday experience of anyone who buys a home. The bigger the mortgage, the more percentage risk the equity faces from changes in housing prices.

Q16. Please provide an example that illustrates why market values are relevant.

A16. Suppose in the above example that the investor has invested in real estate 10 years ago. Further assume that depreciation has reduced the book value of the real estate from $100,000 to $75,000 and assume the investor has paid off 40 percent of his $50,000 mortgage. Thus, the investor has a remaining mortgage of $30,000 (= 60% × $50,000). The book value of the investor's equity investment is therefore $45,000 (= $75,000 - $30,000).

What happens now if real estate prices rise or fall 20 percent? To answer that question, we need to know how real estate prices have developed over the past 10 years. If the market value of the real estate now is $200,000 then a 20 percent decrease in the price of real estate ($40,000) is almost equal to the investor's book value equity. However, his market value equity (or net worth) is equal to the value of the real estate minus what he owes on the mortgage. If we assume that the market value of the mortgage equals the unpaid balance ($30,000), then the investor's net worth is calculated as follows:

$$\begin{aligned} \text{Net Worth} &= \text{Market Value of Real Estate} - \text{Remaining Mortgage} \\ &= \$200{,}000 - \$30{,}000 \\ &= \$170{,}000 \end{aligned}$$

Therefore, the rate of return on equity due to a 20 percent decline in real estate prices is calculated in Table E-2.

Table E-2: Calculating the Rate of Return on Equity

Decline in Real Estate Value	$40,000
Market-Value Equity	$170,000
Rate of Return on Equity	- $40,000/$170,000 = -23.5%

B. The Impact Of Income And Interest

Q17. How does earning income from the investment and paying interest on debt affect the results?

A17. In the following explanation, I ignore income taxes which I deal with in Section C below. Assume the investor is receiving income, e.g., rent, from the real estate. Specifically, assume the investor receives $500 per month in income after all non-interest expenses ($6,000 per year). Also, assume that the expected appreciation is 5 percent per year, so the expected market value is $105,000 after one year. Then the expected rate of return from the real estate with all equity financing is:

$$\text{Expected Return on Equity @ 0\% debt} = \frac{\text{Expected Net Income + Expected Appreciation}}{\text{Initial Investment}}$$

$$= \frac{\$6{,}000 + (\$105{,}000 - \$100{,}000)}{\$100{,}000}$$

$$= 11\%$$

Now suppose that the mortgage interest rate were 5 percent. Then at a mortgage equal to 50 percent, or $50,000, interest expense would be ($50,000 x 0.05), or $2,500. The expected equity rate of return would be:

$$\text{Expected Return on Equity @ 50\% debt} = \frac{\text{Expected (Net Income + Appreciation) – Int. Expense}}{\text{Initial } \textit{Equity} \text{ Investment}}$$

$$= \frac{\$6{,}000 + \$5{,}000 - \$2{,}500}{\$50{,}000}$$

$$= 17\%$$

Notice that the expected return on equity is higher as is the risk carried by equity.

Q18. Can you provide a more general illustration?

A18. Yes. Figure E-3 uses these assumptions at different mortgage levels to plot both (i) the expected rate of return on the equity in the dwelling, and (ii) the realized rate of return on

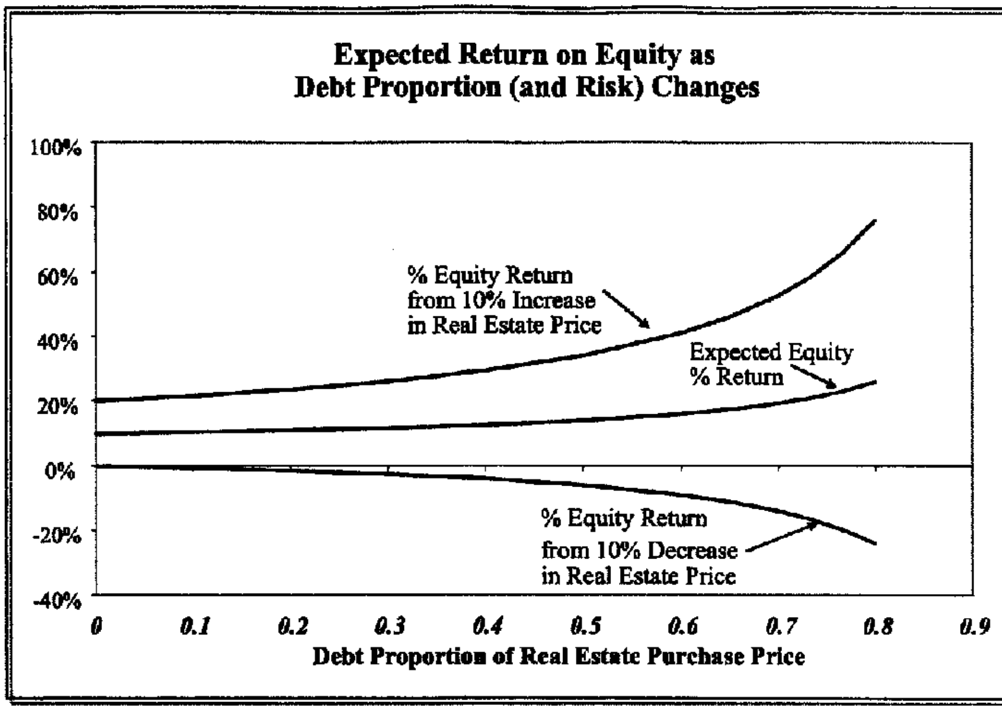

Figure E-3

that equity in a year if the dwelling value increases by 10 percent more than the expected 5 percent rate (i.e., if the value increases by 15 percent) or by 10 percent less than expected (i.e., if it decreases by 5 percent).[24]

The expected rate of return on equity increases at an increasing rate as the investor finances more and more of the real estate through loans (e.g., with a mortgage). Since equity bears all the risk of increases or decreases in real estate values (absent financial distress or bankruptcy), the amount of risk the buyer bears grows at an ever increasing rate as the mortgage percentage also increases.

Q19. What are the implications of this example?

A19. Any time an individual or a company uses debt to finance part an investment, the same risk magnifies. For example, if an investor buys stocks "on margin" -- by borrowing part

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[24] For simplicity, the figure assumes the debt's interest rate is independent of the debt proportion. This might not always be true, and in general would not be true for a corporation that issued debt. However, the general shape of the graphs remains the same.

of the money used to buy the stock -- the expected rate of return will be higher as will the risks the investor carries. As an everyday example, imagine investing your retirement savings in a stock portfolio bought with as much margin as possible. If you were lucky, you could end up living very well in retirement. But you would be taking a lot of risk on the opposite outcome, since your portfolio could decline by more than 100 percent of your initial investment.

The same risk-magnifying effects happen when companies borrow to finance part of their investments.

C. THE EFFECT OF TAXES

Q20. What is the impact of taxes?

A20. Analyzing the net effect of taxes in capital structure decisions by corporations is an important part of the financial research. (Other parts of that research address such issues as the risk of financial distress or bankruptcy, and the signals corporations send investors by the choice of how to finance new investments.) The bottom line is that taxes complicate the picture without changing the basic conclusion.

Q21. Please describe the potential impact of taxes.

A21. Interest expense is tax-deductible for corporations. That increases the pool of cash the corporation gets to keep out of its operating earnings (i.e., its earnings before interest expense). With no debt, 100 percent of operating income is subject to taxes. With debt, only the equity part of the operating income is subject to taxes.

All else equal, the extra money kept from operating income increases the value of the corporation. The standard way to recognize that increase in value is to use an after-tax weighted-average cost of capital as a discount rate when valuing a company's operating cash flows.

Q22. Do personal taxes affect the value of debt, too?

A22. Yes, but in the other direction. One offset to debt's tax benefits at the corporate level is its higher tax burden at the personal level. Investors care about the money they get to keep after all taxes are paid, and while the corporation saves taxes by opting for debt over equity, individuals pay more taxes on interest than on capital gains from equity (and for now, on dividends as well).

Q23. Are there factors other than taxes matter?

A23. Absolutely, "all else" does not remain equal as more debt is added. The more debt, the more the non-tax effects of debt offset the tax benefits. Other costs include such effects as a loss of flexibility, the possibility of sending negative signals to investors, and a host of costs and risks associated with the danger of financial distress.

Q24. Does the tradeoff between the tax and non-tax effects of debt mean that firms have well-defined, optimal capital structures?

A24. No, this sort of "tradeoff" model does not explain actual corporate behavior. A substantial body of economic research confirms that real-world corporations act as if, after a moderate amount of debt is in place, the tax benefits of debt are not worth debt's other costs. In country after country and in industry after industry, the most profitable corporations in an industry tend to use the least debt. The research on this point is quite thorough, and the finding that the most profitable companies tend to use the least debt in a given industry is robust. Yet these are the companies with the most operating income to shield from taxes, who would benefit most if interest tax shields were truly valuable net of debt's other costs. They also presumptively are the best-managed on average (else why are they the most profitable?). This means it is unrealistic to suppose that more debt is always better, or that greater tax savings due to higher interest expense always add value to the firm on balance.

Q25. If the tradeoff model doesn't explain capital structure decisions by firms, is there a model that does?

A25. No single model has (yet) emerged as 'the" explanation of capital structure. However, several alternative models attempt to model the tradeoff (e.g., the "pecking order" hypothesis and "agency cost" explanations).

Q26. What does the absence of an agreed theory of capital structure in the financial literature imply about the overall effect of debt on the value of the firm?

A26. The findings of the financial literature mean that within an industry, there is no well-defined optimal capital structure. The use of some debt does convey some value advantage in most industries, but that advantage is offset by other costs as firms add more debt.[25] The range of capital structures over which the value of the firm in any industry is maximized is wide and should be treated as flat. The location and level of that range, however, does vary from industry to industry, just as the overall cost of capital varies from industry to industry.

Figure E-4 illustrates the picture that emerges from the research. This figure shows the present value of an investment in each of four different industries. For simplicity, the investment is expected to yield $1.00 per year forever. For firms in relatively high-risk industries (Industry 1 in the graph, the lowest line), the $1.00 perpetuity is not worth much and any use of debt decreases firm value. For firms in relatively low-risk industries (Industry 4 in the graph), the perpetuity is worth more and substantial amounts of debt make sense. Industries 2 and 3 are intermediate cases.

The maximum net rate at which taxes can increase value in this figure equals 20 percent of interest expense, representing a balance between the corporate tax advantage to debt

[25] Note that if debt did increase the value of the firm materially, competition would tend to take that value away, since issuing debt is an easy-to-copy competitive strategy. Prices would fall as firms copied the strategy, lowering operating earnings and passing the net tax advantages to debt through to customers (just as happens under rate regulation). Therefore, if also there were a narrow range of optimal capital structures within an industry, competition would drive all firms in the industry to capital structures within that range. This does not happen in practice, which contradicts one or both of the assumptions, i.e., (1) that debt adds material value on balance, and/or (2) that there is a narrow range of optimal capital structures.

and the personal tax disadvantage. The figure plots the maximum possible impact of taxes on value as a separate line, starting at the all-equity value of the lowest-risk industry (Industry 4).

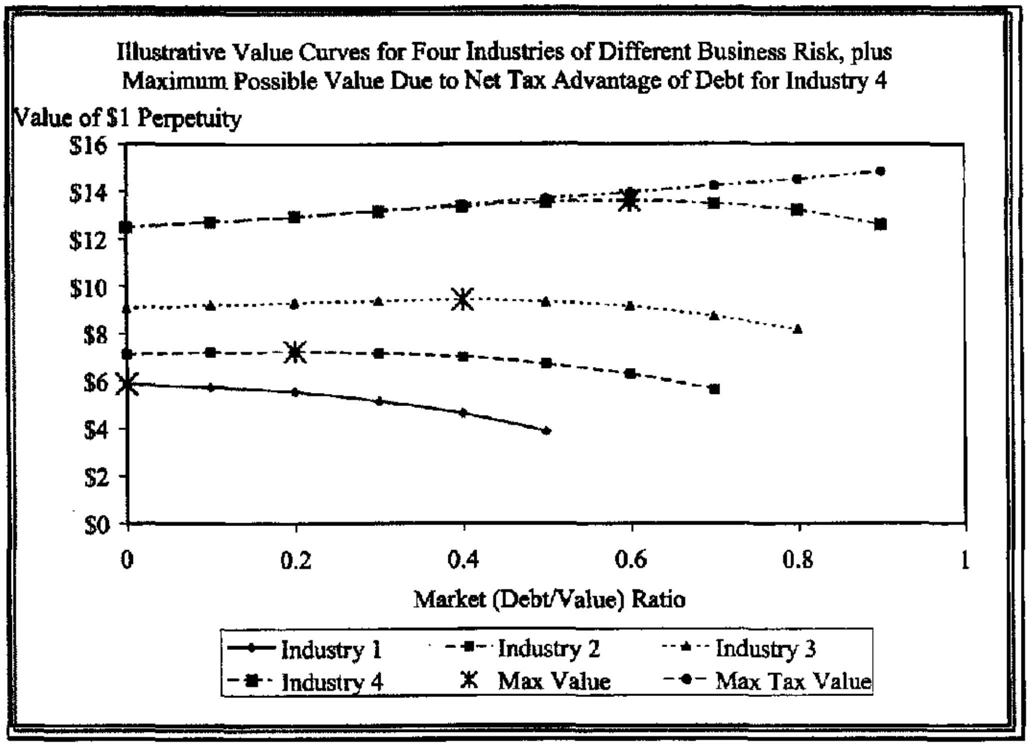

Figure E-4

Figure E-4 identifies a particular point as the maximum value on each of the four curves. However, the research shows that reliable identification of this maximum point, except in the extreme case where no debt should be used, is impossible. In accord with the research, the graph is prepared so that in none of the industries does a change in capital structure make much difference near the top of the curve. Even Industry 4, which increases in value at the maximum rate as quite a lot of debt is added, eventually must reach a broad range where changes in the debt ratio make little difference to firm value, given the research. For Industry 4, debt makes less than a 2 percent difference in the total value of the firm for debt-to-value ratios between 40 and 70 percent. (While these particular values are illustrative, numbers of this order of magnitude are the only ones consistent with the research.)

Q27. What does this imply for the overall cost of capital?

A27. Figure E-5 plots the after-tax weighted-average costs of capital ("ATWACCs") that correspond to the value curves in Figure E-4. This picture just turns Figure E-4 upside down.[26] All the same conclusions remain, except that they are stated in terms of the overall cost of capital instead of the overall firm value. In particular, except for high-risk industries, the overall cost of capital is essentially flat across a broad middle range of capital structures for each industry, which is the only outcome consistent with the research. For Industry 4, for example, the ATWACC changes by less than 15 basis points for debt-to-value ratios between 40 and 70 percent.

[26] Note that the actual estimated ATWACC at higher debt ratios will tend to underestimate the ATWACC that corresponds to the value curves in Figure E-4, which are depicted in Figure E-5, and so will tend to overestimate the value of debt to the firm. The reason is that some of the non-tax effects of excessive debt, such as a loss of financial flexibility, may be hard to detect and not show up in cost of capital measurement.

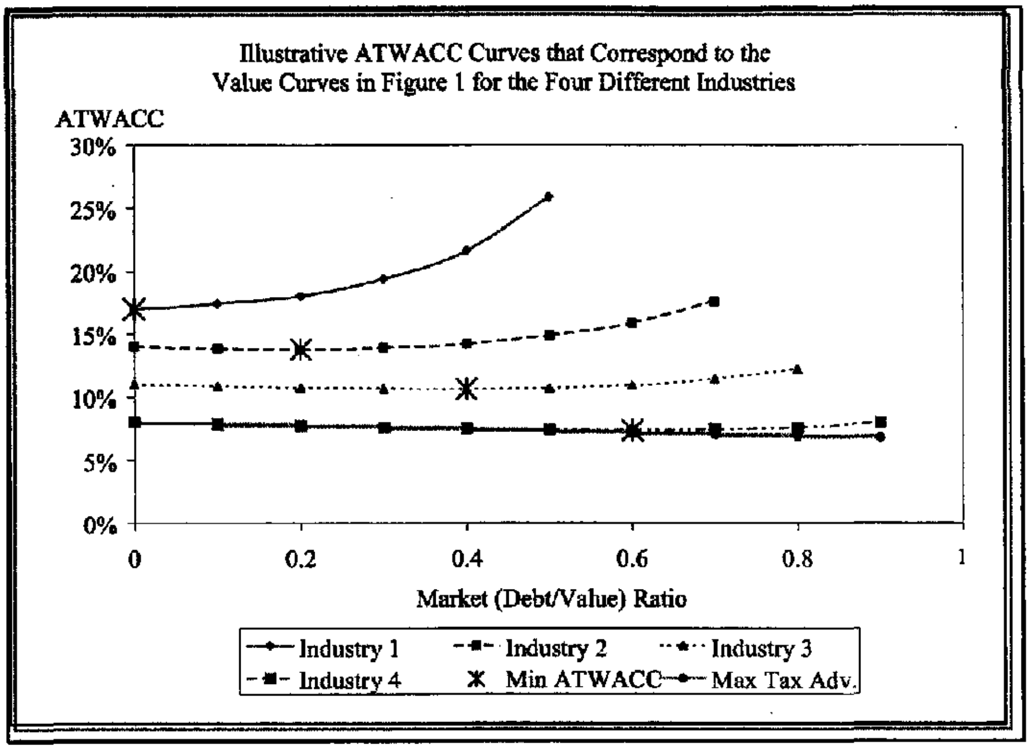

Figure E-5

Q28. How does this discussion relate to estimation of the right cost of equity for ratemaking purposes?

A28. When an analyst estimates the cost of equity for a sample of companies, s/he does so at the sample's actual market-value capital structure. That is, the sample evidence corresponds to ATWACCs that are already out somewhere in the broad middle range in which changes in the debt ratio have little or no impact on the overall value of the firm or the ATWACC.

An analyst therefore should assume the ATWACCs for the sample companies are literally flat. This assumption always provides the exact tradeoff between the cost of equity and capital structure at the literal minimum of the company's ATWACC curve. The research shows that this minimum is actually a broad, flat region, as depicted above. If the company happens to be somewhat to one side or the other of the literal minimum within this region, the recommended procedure may lead to a small understatement or overstatement of the amount that the cost of equity will change as capital structure changes. The degree of this under- or overstatement, however, is very small compared to the inherent uncertainty in estimating the cost of equity in the first place. Otherwise, the financial research would have found very different results about the existence of a narrowly defined optimal capital structure.

D. COMBINED EFFECTS

Q29. Please summarize the implications for the combined impact of the tax and non-tax effects of debt.

A29. The most profitable firms do not behave as if the precise amount of debt they use makes any material difference to value, and competition does not force them into an alternative decision, as it would if debt were genuinely valuable. The explanation that fits the facts and the research is that within an industry, there is no well-defined optimal capital structure. Use of some debt does convey an advantage in most industries, but that advantage is offset by other costs as firms add more debt. The range of capital structures over which the value of the firm in any industry is maximized is wide and should be treated as flat. The location and level of that range, however, does vary from industry to industry, just as the overall cost of capital varies from industry to industry. To conclude that more debt does add more value, once the firm is somewhere in the normal range for the industry, is to conclude that corporate management in general is either blind to an easy source of value or otherwise incompetent (and that their competitors let them get away with it).

The finding that there is no narrowly defined optimal capital structure implies that analysts should estimate the ATWACCs for a sample of companies in a given industry and treat the average ATWACC value as independent of capital structure (at least within a broad middle range of capital structures). The right cost of equity for a rate-regulated company in the same industry is the number that yields the same ATWACC at the capital structure used to set the revenue requirement, since that is the cost of equity that (estimation problems aside) the sample companies would have had if their market-value capital structures had been equal to the regulatory capital structure.

THE EAST OHIO GAS COMPANY d/b/a DOMINION EAST OHIO
Case No. 07-0829-GA-AIR
Rate of Return Summary

Date of Capital Structure: March 31, 2007
Type of Filing: Original
Work Paper Reference Nos.:

Schedule PCD-1

Sponsoring Witness:
M. Vilbert

Line No.	Class of Capital	Reference	Amount	% of Total	Cost (%)	Weighted Cost (%)
1	Long-Term Debt	D-3	$ 16,467,054,606	54.33%	6.05%	3.29%
2	Preferred Stock	D-4	251,495,616	0.83%	6.25%	0.05%
3	Common Equity		13,592,347,823	44.84%	12.00%	5.38%
4	Total Capital		$ 30,310,898,045			8.72%
5	Accumulated Deferred Investment Tax Credit		$ 32,610,491			
6	Accumulated Deferred Income Taxes (Accelerated Amortization)		$ -			
7	Accumulated Deferred Income Taxes (Other Property)		$ 5,613,175,736			

Note: Data provided is for Dominion Resources, Inc. - Consolidated Balance Sheets (unaudited)

THE EAST OHIO GAS COMPANY d/b/a DOMINION EAST OHIO
Case No. 07-0829-GA-AIR
Embedded Cost of Short-Term Debt

Date of Short-Term Debt: March 31, 2007
Type of Filing: Original
Work Paper Reference Nos.:

Schedule PCD-2
Page 1 of 1
Sponsoring Witness:
M. Vilbert

Line No.	Issue (A)	Amount Outstanding (B)	Interest Rate (C)	Interest Requirement (D)
1	Short-Term Commercial Borrowing	$ 1,813,443,390	5.189%	$ 94,090,510
2	Totals	$ 1,813,443,390		$ 94,090,510
3	Cost of Short-Term Debt (D / B)			5.19%

Note: Data provided is for Dominion Resources, Inc. - Consolidated Balance Sheets (unaudited)

THE EAST OHIO GAS COMPANY d/b/a DOMINION EAST OHIO
Case No. 07-0829-GA-AIR
Embedded Cost of Long-Term Debt

Date of Long-Term Debt: March 31, 2007
Type of Filing: Original
Work Paper Reference Nos.:

Schedule PCD-3
Page 1 of 1
Sponsoring Witness:
M. Vilbert

Line No.	Debt Issue Type, *Coupon Rate*	Date Issued (Mo/Day/Yr) (A)	Maturity Date (Mo/Day/Yr) (B)	Principal Amount (C)	Face Amount Outstanding (D)	Unamortized (Discount) or Premium (E)	Unamortized Debt Expense (F)	Unamortized Gain (Loss) on Reacq. Debt (G)	Carrying Value (H=D+E-F+G)	Other Related Unamortized Costs* (I)	Full Carrying Value (J=D+E-F+G+I)	Annual Interest Cost (K)	
1	Dominion Resources Inc., Consolidated												
2	7.83% JSD - Institutional	12/8/1997	12/1/2027	$ 257,732,000	$ 257,732,000	$ -	$ 14,475,162	$ -	$ 243,256,838	$ -	$ 243,256,838	$ 20,442,319	
3	8.4% JSD - Institutional	1/12/2001	1/15/2031	257,732,000	257,732,000	(2,701,497)	2,416,229	-	252,614,274	-	252,614,274	21,715,670	
4	7.8% JSD - Retail	10/23/2001	10/31/2041	206,185,575	206,185,575	-	6,483,265	-	199,702,310	-	199,702,310	16,117,265	
5	7.375% JSD - Retail	8/23/2002	7/30/2042	412,371,150	412,371,150	-	12,751,220	-	399,619,930	-	399,619,930	30,483,939	
6	Possum - Bank	8/22/2000	8/22/2007	94,537,650	146,719,418	-	556,881	-	146,162,537	-	146,162,537	10,374,430	
7	Possum - Equity	8/22/2000	8/22/2007	12,515,250	12,515,250	-	-	-	12,515,250	-	12,515,250	889,834	
8	Possum - Hatteras CP	8/22/2000	8/22/2007	262,947,100	210,765,332	-	-	-	210,765,332	-	210,765,332	13,004,221	
9	MTN F02	11/25/1998	11/25/2008	120,000,000	120,000,000	-	237,356	-	119,762,644	-	119,762,644	7,019,428	
10	92-D Mtg Bond	7/14/1992	7/1/2007	215,000,000	215,000,000	(8,850)	54,218	(584,170)	214,352,762	(23,587)	214,329,175	19,057,179	
11	LOR 89-A ($5M) Mtg Bond	3/5/1992	2/1/2019			-	-	-	-	-	-	18,422	
12	LOR 89-A ($15M) Mtg Bond	9/30/1993	2/1/2019			-	-	-		-	-	64,537	
13	LOR 89-A ($11M) Mtg Bond	11/3/1993	3/1/2019			-	-	-	-	-	-	47,327	
14	DallasTown Mortgage (X)	1/1/1950	12/8/2008	6,800,000	4,000,000	-	-	-	4,000,000	-	4,000,000	300,000	
15	98-A KINCAID	4/28/1998	6/15/2020	265,800,000	213,492,218	-	2,740,508	-	210,751,710	-	210,751,710	15,929,626	
16	Louisa 84	12/28/1984	12/1/2008	60,000,000	60,000,000	-	-	-	60,000,000	(32,661)	59,967,339	2,328,982	**
17	Prince William 86	10/8/1986	8/1/2016	11,200,000	11,200,000	-	-	-	11,200,000	184	11,200,184	415,500	**
18	Grant 86	11/20/1986	8/1/2016	7,400,000	7,400,000	-	-	-	7,400,000	(94,941)	7,305,059	288,412	**
19	Louisa 87	12/9/1987	12/1/2015	18,000,000	18,000,000	-	-	(229,276)	17,770,724	(47,306)	17,723,418	721,313	**
20	Halifax 92	11/24/1992	11/1/2027	56,000,000	56,000,000	-	-	-	56,000,000	(167,784)	55,832,216	2,189,951	**
21	Grant 94	3/30/1994	9/1/2024	19,500,000	19,500,000	-	-	(76,285)	19,423,715	(102,110)	19,321,605	727,843	**
22	Grant 96	2/29/1996	3/1/2026	24,500,000	24,500,000	-	-	-	24,500,000	(205,860)	24,294,140	927,182	**
23	Louisa 94	1/20/1994	1/1/2024	19,500,000	19,500,000	-	-	(249,155)	19,250,845	(333,443)	18,917,402	1,083,552	**
24	Louisa 97	4/8/1997	4/1/2022	10,000,000	10,000,000	-	-	-	10,000,000	(143,386)	9,856,614	244,559	**
25	Louisa 00	9/19/2000	9/1/2030	30,000,000	30,000,000	-	-	-	30,000,000	(60,597)	29,939,403	707,588	**
26	Louisa 01	3/28/2001	3/1/2031	50,000,000	50,000,000	-	-	-	50,000,000	(130,224)	49,869,776	2,180,445	**
27	Chesterfield 87C (post fix)	9/10/1987	12/1/2007	15,000,000	15,000,000	-	-	(14,360)	14,985,640	(6,521)	14,979,119	773,353	**
28	Chesterfield 87B (post fix)	6/4/1987	6/1/2017	35,000,000	35,000,000	-	-	-	35,000,000	(112,333)	34,887,667	2,064,333	**
29	Chesterfield 87A (post fix)	6/4/1987	6/1/2017	40,000,000	40,000,000	-	-	(823,154)	39,176,846	(128,965)	39,047,881	2,417,483	**
30	Chesterfield 85 (post fix)	11/13/1985	10/1/2009	40,000,000	40,000,000	-	-	-	40,000,000	(38,436)	39,961,564	2,214,370	**
31	York 85 (post fix)	11/21/1985	7/1/2009	70,000,000	70,000,000	-	-	-	70,000,000	(56,149)	69,943,851	3,873,489	**
32	Chesapeake 85 (post fix)	11/13/1985	2/1/2008	30,000,000	30,000,000	-	-	-	30,000,000	(10,439)	29,989,561	1,587,280	**
33	Louisa 85 (post fix)	12/18/1985	12/1/2008	62,000,000	62,000,000	-	-	-	62,000,000	(39,549)	61,960,451	3,277,751	**
34	Mecklenburg IDA Bonds	8/18/2004	10/15/2017	24,500,000	24,500,000	641,521	-	-	25,141,521	-	25,141,521	1,540,624	
35	Pennsylvania 94B	11/29/2004	1/1/2010	5,400,000	2,800,000	105,263	-	-	2,905,263	-	2,905,263	161,856	
36	Brayton 2006	2/13/2006	2/1/2036	47,000,000	47,000,000	-	1,344,172	-	45,655,828	-	45,655,828	2,370,208	
37	05-D Sr Notes	9/28/2005	9/28/2007	1,000,000,000	1,000,000,000	-	767,043	-	999,232,957	-	999,232,957	56,888,087	
38	DCI Fin46 Debt	2/17/2005	1/16/2017	385,000,000	385,000,000	-	-	-	385,000,000	-	385,000,000	21,906,500	
39	06-B Sr Notes	11/14/2006	11/14/2008	400,000,000	400,000,000	-	902,228	-	399,097,772	-	399,097,772	22,208,089	
40	00-A Sr Notes	6/26/2000	6/15/2010	700,000,000	700,000,000	(278,652)	1,960,582	-	697,760,767	1,733,877	699,494,644	57,015,424	
41	93-B Debentures (post mod)	12/16/1993	12/1/2015	150,000,000	150,000,000	(1,390,795)	326,713	-	148,282,492	(1,809,814)	146,472,678	10,664,096	
42	01-A Sr Notes	4/17/2001	4/13/2011	500,000,000	500,000,000	(328,207)	1,752,840	-	497,918,953	-	497,918,953	34,702,606	
43	01-C Sr Notes	10/25/2001	11/1/2011	450,000,000	450,000,000	(376,762)	1,723,836	-	447,899,402	-	447,899,402	28,520,890	
44	LDNG Sr Notes	11/1/2001	12/1/2007	200,000,000	200,000,000	409,227	-	-	200,409,227	-	200,409,227	11,530,724	
45	02-B Sr Notes	6/27/2002	6/30/2012	500,000,000	500,000,000	(553,079)	2,164,637	-	497,282,284	780,919	498,063,203	31,567,809	
46	02-C Sr Notes	9/16/2002	9/17/2012	520,000,000	520,000,000	(221,025)	2,112,737	(39,322,956)	478,343,282	17,848,157	496,191,439	24,979,484	
47	98-A Debentures (post swap tav)	10/23/1998	10/15/2010	200,000,000	200,000,000	(636,041)	557,679	-	198,806,280	11,638,416	210,444,696	9,445,374	
48	02-E Sr Notes	12/16/2002	12/15/2032	300,000,000	300,000,000	(689,488)	2,636,109	-	296,674,403	-	296,674,403	20,297,792	
49	02-D Sr Notes	12/16/2002	12/15/2009	300,000,000	300,000,000	(573,502)	866,329	-	298,560,169	(183,983)	298,376,186	15,942,932	
50	03-B Sr Notes	2/13/2003	2/15/2008	400,000,000	400,000,000	(92,263)	492,610	-	399,415,128	-	399,415,128	17,190,591	
51	03-A Sr Notes	2/28/2003	3/1/2013	400,000,000	400,000,000	(410,001)	1,818,650	-	397,771,349	-	397,771,349	19,325,880	
52	03-E Sr Notes	3/6/2003	3/15/2033	300,000,000	300,000,000	(82,529)	2,584,917	-	297,332,553	-	297,332,553	18,940,562	
53	03-D Sr Notes	3/6/2003	3/15/2013	300,000,000	300,000,000	(386,541)	1,340,752	-	298,272,708	-	298,272,708	15,249,255	
54	03-F Sr Notes (2015 Put)	7/24/2003	8/1/2033	510,000,000	510,000,000	(3,266,431)	2,814,565	-	503,919,005	6,388,243	510,307,247	26,393,708	
55	03-A Sr Notes	12/1/2003	3/1/2014	200,000,000	200,000,000	(997,015)	1,074,886	-	197,988,099	(132,811)	197,855,288	10,258,458	
56	03-C Sr Notes	12/9/2003	12/15/2015	200,000,000	200,000,000	(1,146,304)	1,127,951	1,152,149	198,877,894	-	198,877,894	10,602,143	
57	03-B Sr Notes	12/9/2003	12/15/2010	230,000,000	230,000,000	(820,578)	871,773	-	228,307,649	-	228,307,649	10,773,676	
58	CAPES	12/12/2003	12/15/2038	225,000,000	225,000,000	(11,572)	587,649	-	224,400,778	4,701,563	229,102,342	13,588,759	
59	04-A Sr Notes	1/15/2004	1/15/2016	200,000,000	200,000,000	(56,172)	1,223,026	-	198,720,802	-	198,720,802	10,507,005	
60	Remarketed 00-E Notes	9/15/2004	9/15/2014	250,000,000	250,000,000	-	-	-	250,000,000	2,568,818	252,568,818	17,435,396	
61	04-A Sr Notes	11/18/2004	12/1/2014	400,000,000	400,000,000	(1,015,402)	2,345,111	-	396,639,488	(967,141)	395,672,347	20,461,155	
62	04-A Sr Notes (Mock Exchange)	11/22/2004	10/15/2017	105,800,000	90,200,000	8,626,704	-	-	98,826,704	-	98,826,704	4,863,962	
63	96-A Debentures (2006 Put) (Post Amort of FV)	10/21/1996	10/15/2026	150,000,000	150,000,000	1,108,540	-	-	151,108,540	-	151,108,540	10,325,332	
64	97-A Debentures (Post Amort of FV)	12/15/1997	12/15/2027	300,000,000	300,000,000	(2,121,526)	2,486,996	-	295,391,478	(5,747,148)	289,644,330	21,122,250	
65	96-B Debentures (Post Amort of FV)	12/13/1996	12/1/2008	150,000,000	150,000,000	(39,066)	161,636	-	149,799,298	(504,389)	149,294,909	10,426,756	
66	Rosemary 8.625% Notes	2/8/2005	2/15/2016	62,336,321	48,543,664	1,374,849	-	-	49,918,513	-	49,918,513	3,954,802	
67	05-A Sr Notes	6/20/2005	12/15/2010	300,000,000	300,000,000	(229,615)	1,404,398	-	298,365,987	-	298,365,987	14,657,617	
68	05-B Sr Notes	6/20/2005	6/15/2035	300,000,000	300,000,000	-	2,762,599	-	297,237,401	-	297,237,401	17,887,580	
69	05-B Sr Notes (Reopen)	7/14/2005	6/15/2035	200,000,000	200,000,000	3,519,103	1,784,478	-	201,734,625	-	201,734,625	11,875,849	
70	05-C Sr Notes	7/14/2005	7/15/2015	500,000,000	500,000,000	(703,837)	3,014,587	-	496,281,575	(2,471,855)	493,809,720	26,516,223	
71	06-A Sr Notes	1/13/2006	1/15/2016	450,000,000	450,000,000	(1,053,938)	2,762,791	-	446,183,271	-	446,183,271	24,658,943	
72	06-B Sr Notes	1/13/2006	1/15/2036	550,000,000	550,000,000	(1,124,788)	4,902,365	-	543,972,847	-	543,972,847	33,089,417	
73	Remarketed 02-A Sr Notes	2/21/2006	9/15/2008	329,908,750	330,000,000	-	-	-	330,000,000	-	330,000,000	18,803,972	
74	06-A Sr Notes	11/14/2006	11/15/2016	250,000,000	250,000,000	(19,432)	1,631,961	-	248,348,607	(6,884,664)	241,463,943	15,106,791	
75	03-G Sr Notes (Converts)	12/11/2003	12/15/2023	220,000,000	229,000	-	-	-	229,000	-	229,000	7,289	
76	04-C Sr Notes (Converts)	12/22/2004	12/15/2023	219,258,000	219,701,000	-	-	-	219,701,000	-	219,701,000	4,703,802	
77	Fort Story	12/15/2004	1/15/2025	144,996	136,900	-	-	-	136,900	(1)	136,899	9,925	
78	Fort Eustis	12/15/2004	1/15/2025	297,215	280,619	-	-	-	280,619	(1)	280,618	20,345	
79	Fort Monroe	2/17/2005	3/17/2025	2,133,076	2,023,450	-	-	-	2,023,450	(8)	2,023,442	146,701	
80	Fort Lee	4/1/2005	4/1/2032	6,156,544	5,999,215	-	-	-	5,999,215	-	5,999,215	434,943	
81	06-A JSN	6/23/2006	6/30/2066	300,000,000	300,000,000	(1,016,138)	4,828,716	-	294,155,147	-	294,155,147	22,523,647	
82	06-B JSN	9/29/2006	9/30/2066	500,000,000	500,000,000	(837,958)	7,853,090	-	491,308,952	-	491,308,952	31,521,068	
	Totals			$ 16,901,055,627	$ 16,596,026,791	$ (7,343,798)	$ 106,705,231	$ (40,147,207)	$ 16,441,830,535	$ 25,224,071	$ 16,467,054,606	$ 996,833,860	
	Embedded Cost of Long-Term Debt (K / H)											6.06%	
	Full Embedded Cost of Long-Term Debt (K / J)											6.05%	

Note: Data provided is for Dominion Resources, Inc. - Consolidated Balance Sheets (unaudited)

* Other Related Unamortized Costs may include one or more of the following: Preissuance Hedge Loss/Gain, Embedded Option Receipt/Payment, and/or Swap Termination Gain/Loss.
** Put Bonds are amortized to Put Date.

THE EAST OHIO GAS COMPANY d/b/a DOMINION EAST OHIO
Case No. 07-0829-GA-AIR
Embedded Cost of Preferred Stock

Date of Preferred Stock: March 31, 2007
Type of Filing: Original
Work Paper Reference Nos.:

Schedule PCD-4
Page 1 of 1
Sponsoring Witness:
M. Vilbert

Line No.	Dividend Rate, Type, Par Value	Date Issued (A)	Dollar Amounts Outstanding at Par Value ($) (B)	Premium or (Discount) (C)	Issue Expense (D)	Gain (Loss) on Reacquired Stock (E)	Net Proceeds (F=B+C-D+E)	Annual Dividends (G)
1	$5.00 Preferred Stock	5/25/1944	$ 10,667,700	$ 1,493,478	$ 301,912	$ 190,656	$ 12,049,922	$ 533,385
2	$4.04 Preferred Stock	3/14/1950	1,292,600	29,342	212,844	185,293	1,294,391	52,221
3	$4.20 Preferred Stock	3/14/1951	1,479,700	36,993	204,313	174,081	1,486,460	62,147
4	$4.12 Preferred Stock	12/14/1955	3,253,400	56,284	243,727	180,309	3,246,266	134,040
5	$4.80 Preferred Stock	8/1/1962	7,320,600	-	554,141	418,888	7,185,347	351,389
6	$7.05 Preferred Stock	7/8/1993	50,000,000	-	570,801	(1,194,065)	48,235,134	3,525,000
7	$6.98 Preferred Stock	8/18/1993	60,000,000	-	627,748	(2,590,002)	56,782,250	4,188,000
8	Flex MMP 2002 Series	12/12/2002	125,000,000	(1,909,154)	1,875,000	-	121,215,846	6,875,000
9	Issuance Cost re: Flex MMP 2002 Series		(1,916,654)					
10	Totals		$ 257,097,346	$ (293,058)	$ 4,590,486	$ (2,634,840)	$ 251,495,616	$ 15,721,182
11	Embedded Cost of Preferred Stock (G / F)							6.25%

Note: Data provided is for Dominion Resources, Inc. - Consolidated Balance Sheets (unaudited)

Table No. MJV-1

Index to Tables for the Written Evidence of Michael J. Vilbert

Table No. MJV-1	Table of Contents
Table No. MJV-2	Company Classification by Percent of Regulated Assets
Table No. MJV-3	Market Value of the US Gas LDC Sample
Table No. MJV-4	Capital Structure Summary of the US Gas LDC Sample
Table No. MJV-5	Estimated Growth Rates of the US Gas LDC Sample
Table No. MJV-6	DCF Cost of Equity of the US Gas LDC Sample
Table No. MJV-7	Overall After Tax DCF Cost of Equity of the US Gas LDC Sample
Table No. MJV-8	DCF Cost of Equity at Dominion East Ohio's Capital Structure
Table No. MJV-9	Normalized Risk-Free Rates
Table No. MJV-10	Risk Positioning Cost of Equity of the US Gas LDC Sample
Table No. MJV-11	Overall Risk Positioning Cost of Equity of the US Gas LDC Sample
Table No. MJV-12	Risk Positioning Cost of Equity at Dominion East Ohio's Capital Structure

Table No. MJV-2

US Gas LDC Sample

Classification of Companies by Assets

Company		Company Category
Atmos Energy Corp		R
Laclede Group Inc/The	*	R
Northwest Natural Gas Co	*	R
Piedmont Natural Gas Co	*	R
South Jersey Industries Inc		MR
Southwest Gas Corp	*	R
WGL Holdings Inc	*	R
AGL Resources Inc		MR
Vectren Corp		R
New Jersey Resources Corp		MR

Sources and Notes:
Workpaper #1 to Table No. MJV-2, Panels A-J.
* Represents companies included in the subsample.
R = Regulated (greater than 80 percent of total assets are regulated).
MR = Mostly Regulated (50 to 80 percent of total assets are regulated).

Workpaper #1 to Table No. MJV-2

US Gas LDC Sample: Breakdown of Assets

Panel A: Atmos Energy Corp (thousands)

		2006	% of Total Assets
Assets Attributed to Utility	[1]	5,462,301	95.5%
Total	[2]	5,719,547	

Sources and Notes:
[1]-[2]: Atmos Energy Corp's 2006 Form 10-K.

Workpaper #1 to Table No. MJV-2

US Gas LDC Sample: Breakdown of Assets

Panel B: *Laclede Group Inc/The (thousands)*

		2006	% of Total Assets
Assets Attributed to Utility	[1]	763,827	89.5%
Total	[2]	853,515	

Sources and Notes:
[1]-[2]: Laclede Group Inc/The's 2006 Form 10-K.

Workpaper #1 to Table No. MJV-2

US Gas LDC Sample: Breakdown of Assets

Panel C: Northwest Natural Gas Co (thousands)

		2006	% of Total Assets
Assets Attributed to Utility	[1]	see footnote	98.0%
Total	[2]	see footnote	

Sources and Notes:
[1]-[2]: Northwest Natural Gas Co's 2006 Form 10-K, pg 3 explicitly states the percentage of regulated assets.

Workpaper #1 to Table No. MJV-2

US Gas LDC Sample: Breakdown of Assets

Panel D: Piedmont Natural Gas Co (thousands)

		2006	% of Total Assets
Assets Attributed to Utility	[1]	2,600,411	97.2%
Total	[2]	2,676,288	

Sources and Notes:
[1]-[2]: Piedmont Natural Gas Co's 2006 Form 10-K.

Workpaper #1 to Table No. MJV-2

US Gas LDC Sample: Breakdown of Assets

Panel E: South Jersey Industries Inc (thousands)

		2006	% of Total Assets
Assets Attributed to Utility	[1]	1,228,076	78.1%
Total	[2]	1,573,032	

Sources and Notes:
[1]-[2]: South Jersey Industries Inc's 2006 Form 10-K.

Workpaper #1 to Table No. MJV-2

US Gas LDC Sample: Breakdown of Assets

Panel F: Southwest Gas Corp (thousands)

		2006	% of Total Assets
Assets Attributed to Utility	[1]	3,352,074	96.2%
Total	[2]	3,484,965	

Sources and Notes:
[1]-[2]: Southwest Gas Corp's 2006 Form 10-K.