# Large Filing Separator Sheet

Case Number: 11-3549-EL-SSO

Date Filed: 6/20/2011

Section: 4

Number of Pages: ~~200~~ 201

Description of Document: Application

and win tranches. Financial participants (those that do not own generating assets) have won tranches in previous auctions and will continue to have that opportunity going forward. In fact, any bidder that can purchase power for delivery to the Company's service territory can participate in the CBP. Nothing in the CBP requires bidders to own generation and nothing in the CBP provides preferential treatment to those that do own generation. The descending-price clock auction format is nondiscriminatory because anyone can participate as long as they satisfy the criteria used in the application process. Moreover, the CBP is a structured process that levels the playing field for participants and makes information available so no bidders are advantaged. All bidders are bidding on standardized supply contracts and are subject to identical financial and credit requirements and criteria. All bidders have equal access to information before bidding and during the event itself. Prior to the auction, the process to educate and train bidders on the details of the CBP and the products is the same for all bidders. During the auction, all bidders receive the same information about the status of the auction.

**Q. ARE THERE SPECIFIC DESIGN CONSIDERATIONS CHOSEN TO PROMOTE COMPETITION IN THE AUCTION?**

A. There are several rules in place designed to promote competitive bidding. These include the follow:

(a) All bidders adhere to identical credit qualification procedures. Each bidder's credit-based tranche cap is a function of clearly defined, objective criteria. The criteria prevent any potential subjectivity or favoritism in the process.

(b) All bidders are bidding on standardized supply contracts. Contracts are not tailored to accommodate the needs or demands of any individual bidder.

(c) The bidder education and training process is designed to provide all bidders equal access to information. The process includes bidder information sessions to educate all bidders on the CBP, the auction rules, and the products being offered. The Q&A process is designed to provide all bidders equal access to information related to the CBP.

(d) During the auction, all bidders receive the same information about the status of the auction, including prices and the supply and demand conditions.

(e) The closing criteria are applied equally to all bidders. Bids are evaluated and winning bidders are determined based on price alone. Any bidder willing to supply at the announced price remains active in the auction. Any bidder active on a product when the auction closes is guaranteed to win the rights to supply SSO load.

**Q. DOES THE PROPOSED CBP PROTECT AGAINST THE EXERCISE OF MARKET POWER AND, IF SO, HOW?**

A. It is my understanding that the applicable statutory provisions and Commission rules do not require the electric distribution utility to demonstrate that its ESP protects against the exercise of market power. Again, there are no provisions under R.C. 4928.143 applicable to procuring energy supply through a competitive auction format. However, I as discussed above, Duke Energy Ohio's CBP plan has been guided by the requirements set forth in R.C. 4928.142. In that regard and as I understand, the statutes and rules only require that the electric distribution utility belong to a regional transmission organization that is overseen by an independent market monitor that is responsible for protecting against market abuses and the improper exercise of market power. Duke Energy Ohio addresses this requirement through Company witness Kenneth J. Jennings. I would further offer that the CBP plan proposed here provides protection against market power abuses. As reflected in the Communications Protocols, Attachment E to the Application, affiliates of Duke Energy Ohio cannot be provided with any information regarding the CBP plan that would provide them an unfair competitive advantage. Affiliates, as used in the Communications Protocols, include that part of its business that engages in merchant activity. As I have discussed previously, all auction participants are afforded the same amount of information, thus preventing any perceived abuse of market power.

**Q. ARE CHANGES TO THE CBP POSSIBLE?**

A. Although the proposed CBP contains the necessary elements that result in a competitive process, changes may be considered if such changes further promote successful CBP solicitations.

**Q. WERE ALTERNATIVES TO THE PROPOSED CBP PLAN CONSIDERED?**

A. Yes. In addition to a descending-price clock auction format, consideration was given to a one-shot sealed-bid format. Both formats have been used for a number of years to procure electricity and for other competitive bids in electricity and in other industries. A one-shot sealed-bid format is appropriate in some instances and offers the advantage of a potentially simple bidding process. For the types of products being procured here, there is little if any advantage of a one-shot sealed-bid format, and a descending-price clock auction format offers several advantages.

First, with multiple products, it is more difficult in a one-shot sealed-bid format for bidders to specify their bids. The number of tranches they would be willing and able to supply depends on price levels and relative prices for the different products. In principle, they could submit contingent bids, specifying how many tranches for each product they would bid for different combinations of prices, but specifying all the possible combinations of prices would be challenging.

Second, there is a common value element to the CBP products. This means there is some uncertainty in valuing the tranches and the uncertainty is correlated across bidders (*e.g.*, forecasts of market prices in the future). This can give rise to the winner's curse problem in which the winning bidder wins because it has the lowest estimate of the cost of supplying the tranches — thus, a bidder faces the risk that its bid is an outlier compared to the bids of other market participants and wins at a price that is below competitive market levels. Unless the winner's curse risk is addressed through the appropriate auction design, bidders will compensate for the risk by bidding conservatively, leading to potentially higher clearing prices for the procurement. In a one-shot sealed-bid format, the winner's curse can be addressed somewhat by using uniform pricing (all winning bidders for a product get paid the same price for the product) rather than first-price discriminatory bidding (each winning bidder gets paid the price it bid). However, the one-shot sealed-bid format lacks an effective price discovery mechanism that also mitigates the winner's curse — a price discovery mechanism in which bidders gain confidence from price signals reflecting other bidders' bids, thereby encouraging bidders to bid more aggressively.

Third, with multiple products, the more that the products are related in value (*e.g.*, they are substitutes and/or complements), the more important it is that meaningful price signals be provided so that bidders gain information about the value of the tranches, reducing risks for bidders and encouraging them to bid lower prices. A one-shot sealed-bid auction does not provide these price signals, thereby increasing risks faced by bidders and discouraging them from bidding lower prices.

In contrast to the one-shot sealed-bid format, the descending-price clock format allows bidders to revise their bids in response to prices that reflect aggregate bidder interest in the products. Because the auction proceeds in a series of rounds with announced prices reflecting competitive bids, bidders do not need to be concerned with specifying combinations of hypothetical prices. There is an effective price discovery mechanism: prices decline in response to supply being bid, and bidders can adjust their bids accordingly. The descending-price clock format provides the price transparency that facilitates effective and efficient bidding among all bidders. The price signals provided through the process enable bidders to bid confidently and aggressively (*i.e.*, at lower prices) without risking "under-bidding the market". The descending-price clock format also imposes uniform pricing which also reduces bidders' risks. The bidding mechanics for the descending-price clock format are straightforward. It has been my experience that even bidders participating in this bidding format for the first time find the logic, interface, and experience intuitive and efficient.

Fourth, in a simultaneous, multiple-round, descending-price clock procurement, bidders can switch from one of the utility's products to another product in response to price differences that they believe are not reflective of underlying supply cost differences. This behavior leads to a potentially more efficient outcome and contributes to pricing that is more consistent among the products. Similar products will have similar prices through this process. This further simplifies administration and regulatory oversight.

Finally, the descending-price clock format has been used successfully in Ohio in the past. The format performed well and resulted in strong participation from suppliers reflecting the competitive nature of the process. It is a format that participants are used to and are comfortable with.

**Q. WHAT OBSTACLES MIGHT CREATE DIFFICULTIES OR BARRIERS FOR THE ADOPTION OF THE PROPOSED CBP?**

A. There should be no barriers or difficulties for bidders with respect to the proposed CBP. As with any competitive procurement, a critical success factor is whether the products are attractive to bidders and whether bidders have been provided sufficient time and information to evaluate the opportunity to participate. As part of that, any uncertainties in the process that bidders face should be addressed to the extent possible. The proposed CBP products are clearly defined and are designed to be attractive to prospective bidders. The proposed CBP plan is designed to provide sufficient time and readily available information for prospective bidders to participate confidently in the CBP. Thus, as noted, there should be no barriers or difficulties.

## III. <u>THE PROPOSED CBP IS CONSISTENT WITH OHIO LAW</u>

**Q. IS THE PROPOSED CBP CONSISTENT WITH OHIO LAW?**

A. I believe it is. As I have previously discussed, the CBP plan incorporated into Duke Energy Ohio's proposed ESP has been developed with reference to the statutory criteria applicable to a CBP plan under an MRO. Consistent therewith, the CBP plan here provides for all of the following:

(a) Open, fair, and transparent competitive solicitation;

(b) Clear product definition;

(c) Standardized bid evaluation criteria;

(d) Oversight by an independent third party that shall design the solicitation, administer the bidding, and ensure that the criteria specified above are met; and,

(e) Evaluation of the submitted bids prior to the selection of the least-cost bid winner or winners.

**Q. WILL THERE BE LOAD CAPS FOR THE AUCTIONS?**

A. Yes. Although load caps may place upward pressure on the auctions' clearing prices, supplier diversity provides some risk mitigation benefits to the Company and ratepayers. As a result, Duke Energy Ohio is proposing to adopt a load cap for these wholesale energy auctions. The proposed load cap will be 80 percent on an aggregated load basis across all auction products for each auction date such that no bidder may bid on and win more tranches than the load cap. The load cap will be implemented by ensuring that each bidder's initial eligibility does not exceed the load cap in an auction.

**Q. IS THE CBP PLAN AN OPEN, FAIR, AND TRANSPARENT COMPETITIVE SOLICITATION?**

A. The CBP provides for open, fair, and transparent competitive solicitation through the product definition, the information channels, the bidder qualification process, the bidding design, and the rules for participation. The products are familiar to market participants and well-defined and are the same for all bidders. Information about the solicitations will be timely and readily available on an equal basis to interested parties. The bidder qualification process is the same for all participants, familiar to market participants, and fully documented. The version of the descending-price clock auction in the solicitations applies the same bidding rules and procedures to all bidders and is familiar to participants. Finally, all the rules for participating in the solicitation are known to all participants ahead of time and applied equally to all participants. All the above encourages participation, and promotes the openness, fairness, and transparency of the solicitations.

**Q. PLEASE EXPLAIN HOW THE PROPOSED CBP PROMOTES A CLEAR PRODUCT DEFINITION.**

A. The products are standardized and familiar to market participants. The products are load-following, full requirements service including energy and ancillary services. The auction products exclude capacity. The products are well-known and understood in the marketplace, and can be readily evaluated and priced by bidders. All bidders know they are bidding on the same products.

**Q. PLEASE EXPLAIN HOW THE PROPOSED CBP PROVIDES FOR STANDARDIZED BID EVALUATION CRITERIA.**

A. Bidders that submit bids are allowed to submit bids only by first successfully completing the Part 1 and Part 2 Application process. That process uses standardized evaluation criteria applied equally to all applicants, and ensures that bidders allowed to submit bids are willing, able, and committed to satisfying the obligations of an SSO supplier should they win tranches in the bidding. The two-part application process ensures that non-price criteria are satisfied in evaluating the qualifications of bidders to become SSO suppliers. This pre-qualification process further ensures: (i) a level playing field for all bidders; (ii) a clear evaluation of bids such that no bidder can gain an unfair advantage in the process; (iii) that all bidders are judged on the same, standardized basis; and, (iv) that the only necessary evaluation by the Commission is on price. This means that bids subsequently can be evaluated on an objective, price-only basis. The bidding design encourages bidders to bid supply at the lowest possible price. There is no ambiguity as to the winning bids, the winning bidders, and the non-winning bidders. Winning bidders win simply because non-winning bidders are not willing and able to supply tranches at prices as low as the prices at which winning bidders are willing and able to supply the tranches. The Commission's statutory oversight in selecting the least-cost bids also ensures standardized bid evaluation criteria are used.

**Q. PLEASE EXPLAIN HOW THE PROPOSED CBP ALLOWS FOR OVERSIGHT BY AN INDEPENDENT THIRD PARTY.**

A. The Auction Manager, CRA International, has provided independent management and oversight of competitive bids for numerous clients in electricity since the mid 1990s and CRA's remuneration as Duke Energy Ohio's Auction Manager does not depend on the outcome of the CBP solicitations or which bidders win what tranches at what prices.

**Q. PLEASE EXPLAIN HOW THE PROPOSED CBP PROVIDES FOR EVALUATION OF THE SUBMITTED BIDS PRIOR TO THE SELECTION OF THE LEAST-COST BID WINNER OR WINNERS.**

A. After the close of bidding, the Auction Manager will provide the Commission with the post-bidding report that contains the information the Commission needs to evaluate the solicitation and to select the least-cost bid winner(s). Consistent with O.A.C. 4901:1-35-08(B), Duke Energy Ohio proposes that the Auction Manager provide the report within twenty-four hours of the completion of the bidding process. Duke Energy Ohio further anticipates that the report will include a summary of the results of the CBP and all of the elements set forth in O.A.C. 4901:1-35-08(B) (1) through (7). Likewise, although there is no express requirement to do so, Duke Energy Ohio will provide access to its employees and CRA to assist the Commission in its review of the CBP, as well as data, information and communications pertaining to the bidding process, on a real time basis and regardless of the confidential nature of such data and information.

## IV. CONCLUSION

**Q. WERE ATTACHMENTS B, C, D, E, AND G PREPARED UNDER YOUR DIRECTION?**

A. Yes, they were.

**Q. DOES THAT CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

CRA Charles River Associates

# ROBERT J. LEE
Principal

M.S. Industrial Administration, Carnegie Mellon University,

B.A. Mathematics, Boston College

Mr. Lee is a Principal in CRA's Auctions & Competitive Bidding Practice. During his consulting career, Mr. Lee has assisted numerous clients to develop structured sales and procurement channels in an array of industries and markets. He has managed structured transactions, acquisitions and divestitures in both traditional and competitive bidding environments. In addition, Mr. Lee has helped clients on a range of valuations and market analyses related to changes in market dynamics and market structure. Prior to joining CRA, Mr. Lee was a Principal with the PA Consulting Group and at Putnam, Hayes and Bartlett, Inc.

## AUCTIONS, COMPETITIVE BIDDING AND MARKET MECHANISMS

### Electricity

*FirstEnergy Ohio Utilities*

- For FirstEnergy Service Company, currently assisting in designing and conducting ongoing competitive bidding processes using a clock auction format to procure wholesale generation and capacity for retail Standard Service Offer (SSO) load to be delivered starting June 2011 to customers of FirstEnergy Ohio Utilities — Cleveland Electric Illuminating Company, The Toledo Edison Company, and Ohio Edison Company. Two auctions per year starting in 2010 are planned. The auction process and outcome are subject to approval by the Public Utilities Commission of Ohio (PUCO).

- For FirstEnergy Service Company, assisted in designing and conducting a competitive bidding process using a hybrid clock auction and sealed-bid format to procure wholesale generation and capacity for retail Standard Service Offer (SSO) load to be delivered June 2009 through May 2011 to customers of FirstEnergy Ohio Utilities — Cleveland Electric Illuminating Company, The Toledo Edison Company, and Ohio Edison Company. Played a key role on the Auction Manager team including logistics and managing the mock auction and the live event. The successful auction procured more than $6 billion in supplies. The auction process and outcome were subject to approval by the Public Utilities Commission of Ohio (PUCO).

### *RWE*

- Auction Manager for RWE's ongoing power supply auction serving major commercial and industrial customers in Europe. Currently working with RWE and the broader CRA auction team on the auction design framework, including all bidding rules, auction parameters, and bidder support documentation and tools. In addition, Mr. Lee helped to develop and test the customized auction software working with software engineering through the design and testing process. The auction process and outcome are subject to approval by the German cartel office (BKartA).

### *Trans Elect*

- Part of CRA's Auction Manager team on an open season auction process for Trans Elect. The open season auction process used CRA's Auction Management System to successfully sell transmission capacity rights through an open and transparent bidding process. The auction process and outcome were subject to approval by the U.S. Federal Energy Regulatory Commission (FERC).

### *GE EFS*

- Auction Manager for the Linden VFT open season auction process. With CRA's assistance, GE successfully auctioned incremental transmission capacity from PJM into New York's Zone J. Mr. Lee worked closely with GE and the broader CRA team to design and test the customized AMS auction software and to educate bidders on the auction design parameters as well as the VFT technology. The auction process and outcome were subject to approval by the U.S. Federal Energy Regulatory Commission (FERC).

## Agriculture

### *Ocean Spray Cranberries*

- Project Manager and Auction Manager for the development of an Internet-based trading platform for Ocean Spray Cranberries. The system, launched in the summer of 2009, represented a major innovation in an industry that lacked price transparency and adequate market signals for investment. Through the online system, Ocean Spray successfully is offering cranberry concentrate to major beverage producers worldwide.

### *Fonterra - globalDairyTrade*

- Project Manager and Auction Manager for the development and administration of *global*DairyTrade, the Internet-based auction sales channel for a major international dairy cooperative. The auction-based system represents a major departure from the industry status quo and served as a mechanism for cost reduction, efficiency improvement, and increased market transparency for the supplier and its customers. Key responsibilities include contributions on the auction design, software development, customer training processes, and client communications. Through December 2009, nearly US$1 billion in intermediate dairy products have been auctioned and sold to customers worldwide.

## ASSET VALUATION AND MARKET STRATEGY

### *Confidential Client*

- Advised the successful bidder in the acquisition of a gas-fired combined cycle power plant located in a remote region of Pakistan. As part of El Paso's divestiture of its Asian power generating assets, Mr. Lee worked closely with a the buyer to value the portfolio of power sales, fuel supply and O&M contracts supporting the facility. Critical considerations included fuel supply risk, FX risk and the proper assessment of the threat of terrorism associated with the facility.

### *Confidential Client*

- Worked closely with the management of a processed coal producer to identify the product's value versus alternative coal options. Established the breakeven value for the fuel under a range of alternative environmental, coal price and transportation cost scenarios. Helped establish the relevant geographic range under which the fuel could potentially compete and identified attractive utilities for targeted marketing activities. Identified alternative distribution strategies that would help mitigate transportation cost concerns.

### *Hoosier Energy*

- Reviewed the $NO_X$ SIP Call compliance plan for Hoosier Energy, a Midwestern G&T Cooperative. Worked closely with management to develop a new framework for evaluating environmental compliance options at Hoosier's principal coal-fired power stations. Identified key risk factors impacting the value of the cooperative's planned environmental expenditures, including the risk of domestic CO2 restrictions. Identified potential cost saving and risk mitigation strategies in association with pending changes in environmental policies. Proposed alternative allowance banking strategies that would reduce financial exposure associated with SIP investments.

*PSEG*

- Worked with management to evaluate the impact of a range of environmental scenarios on PSEG asset values. Mr. Lee modeled an array of 3P and 4P proposals and evaluated the likely response of market participants. The modeling exercise examined the impact of incremental environmental restrictions on regional and national new capacity builds, PCE retrofits and fuel selection. In addition, the CRA team quantified the impact of proposed or pending regulations on regional power market prices and on the prices for tradable emissions credits.

*Triton Coal*

- Advised the management of Triton Coal on antitrust issues associated with their divestiture of the Buckskin and North Rochelle coal mines located in the Wyoming portion of the Powder River Basin. Identified substitute products including coal from alternative producing basins and power generation from alternative fuels. Identified the market for Powder River Basin coal based on transportation access and costs as well as coal quality considerations. Evaluated bidders based on the potential impact of the acquisition on market concentrations. Balanced the bid price for resources versus the likelihood that a potential sale would withstand DOJ scrutiny.

*Foster Wheeler*

- Performed a strategic assessment of the international coal boiler market for Foster Wheeler. Identified key markets for growth in coal-fired power generation over the near, mid and long-term. Considered key issues such as resource availability, environmental policy uncertainties and power demand growth. Worked closely with Foster Wheeler Oy to identify attractive markets for their CFB coal-boiler marketing activities.

*British Petroleum*

- Examined the potential strategic impacts of btu convergence on coal and oil markets. The analysis evaluated the economics of coal-to-liquids, coal-to-gas and underground coal gasification. Identified regional discontinuities on project economics and participated in workshops designed to assess opportunities in the coal space and their impact on markets for oil, coal and power.

## PRESENTATIONS AND PUBLICATIONS

Brandeis University, Graduate School of International Business, lecturer on coal and environmental markets and energy market dynamics

National Public Radio (NPR), Marketplace, recurrent on air guest discussing coal, environmental markets and environmental policy

"Creating Markets and Structured Sales Channels", presented at the U.S. Apple Association Outlook 2010, Chicago, IL, August 19, 2010

"Not Your Father's Auction", Industry Week, April 2010

"A Better Way to Transact", Beverage Industry: Market Insights, May 2010

"$NO_X$ Trading: Strategies for Electric Cooperatives"; with Anne Smith; Cooperative Research Network, National Rural Electric Cooperative Association; April 2003

## EDUCATION

**CARNEGIE MELLON UNIVERSITY,** Pittsburgh, PA
Graduate School of Industrial Administration
MSIA (MBA)

**BOSTON COLLEGE** Chestnut Hill, MA
College of Arts and Sciences
BA Mathematics

DUKE ENERGY OHIO EXHIBIT ____

**BEFORE**

**THE PUBLIC UTILITIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service. | ) ) ) ) ) ) ) | Case No. 11-3549-EL-SSO |
| In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20. | ) ) ) | Case No. 11-3550-EL-ATA |
| In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Corporate Separation Plan. | ) ) ) | Case No. 11-3551-EL-UNC |

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**REDACTED VERSION**

**DIRECT TESTIMONY OF**

**WILLIAM DON WATHEN JR.**

**ON BEHALF OF**

**DUKE ENERGY OHIO, INC.**

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June 20, 2011

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Attachments:

WDW-1: Revenue Requirement Calculation for Rider RC
WDW-2: Projected Rider RC Calculations and the Better in the Aggregate Test

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is William Don Wathen Jr., and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed by Duke Energy Business Services LLC (DEBS) as General Manager and Vice President of Rates, Ohio and Kentucky. DEBS provides various administrative and other services to Duke Energy Ohio, Inc., (Duke Energy Ohio or the Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

**Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I received Bachelor Degrees in Business and Chemical Engineering, and a Master of Business Administration Degree, all from the University of Kentucky. After completing graduate studies, I was employed by Kentucky Utilities Company as a planning analyst. In 1989, I began employment with the Indiana Utility Regulatory Commission as a senior engineer. From 1992 until mid-1998, I was employed by SVBK Consulting Group, where I held several positions as a consultant focusing principally on utility rate matters. I was hired by Cinergy Services, Inc., in 1998, as an Economic and Financial Specialist in the Budgets and Forecasts Department. In 1999, I was promoted to the position of Manager, Financial Forecasts. In August 2003, I was named to the position of Director -

Rates. On December 1, 2009, I took the position of General Manager and Vice President of Rates, Ohio and Kentucky.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?**

A. Yes. I have presented testimony on numerous occasions before the Public Utilities Commission of Ohio (Commission) and various other state, local, and federal regulators.

**Q. PLEASE SUMMARIZE YOUR DUTIES AS GENERAL MANAGER AND VICE PRESIDENT OF RATES, OHIO AND KENTUCKY.**

A. As General Manager and Vice President of Rates, Ohio and Kentucky, I am responsible for all state and federal rate matters involving Duke Energy Ohio and Duke Energy Kentucky, Inc.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to support various aspects of Duke Energy Ohio's proposed electric security plan (ESP). I provide testimony regarding the primary components of the Company's proposed ESP, provisions for testing the plan in years four and eight pursuant to R.C. 4928.143(E), transitional conditions should the plan be terminated, and the association with governmental aggregators. Finally, I address the comparison between the proposed ESP and the expected results under R.C. 4928.142 in respect of pricing.

## II. PRIMARY COMPONENTS OF THE ESP

**Q. PLEASE DESCRIBE THE PRIMARY COMPONENTS OF DUKE ENERGY OHIO'S PROPOSED ESP.**

A. The Company's proposed ESP is comprised of both cost-based and market-based pricing elements, the intent of which is to provide customers with rate stability and price certainty while retaining their ability to select competitive providers of the energy commodity. The table below summarizes the riders that are incorporated into and a part of the proposed ESP.

| Table 1 – New Riders | | |
|---|---|---|
| **Rider Name** | **Description** | **Avoidable?** |
| Rider RC | Retail Capacity | No |
| Rider PSM | Profit Sharing Mechanism | No |
| Rider RE | Retail Energy | Yes |
| Rider AER-R | Alternative Energy Recovery Rider | Yes |
| Rider RECON | Reconciliation Rider for over-/under-recovery of eliminated ESP-era riders | Yes |
| Rider UE-GEN | Uncollectible Expense Rider for Generation | No |
| Rider DR | Distribution Reliability | No |

Further, certain riders that were approved in Duke Energy Ohio's current ESP under Case No. 08-920-EL-SSO, *et al.*, will be unaffected by this filing. Those riders are Rider SAW, Rider SAW-R, and Rider ECF. As these three riders are unchanged by this Application, I do not discuss them in detail in my testimony.

Finally, upon implementation of the proposed ESP, a number of existing riders will be terminated. Table 2 is a summary of the riders that will be no longer exist under the new ESP.

| Table 2 – Riders Being Eliminated | |
|---|---|
| **Rider Name** | **Description** |
| Rider PTC-BG | Price-to-Compare: Base Generation |
| Rider PTC-FPP | Price-to-Compare: Fuel and Purchased Power |
| Rider PTC-AAC | Price-to-Compare: Annually Adjusted Component |
| Rider SRA-CD | System Reliability Adjustment: Capacity Dedication |
| Rider SRA-SRT | System Reliability Adjustment: System Reliability Tracker |
| Rider DR-IM | Distribution Reliability: Infrastructure Modernization |

### A. Rider RC (Retail Capacity)

**Q. PLEASE DESCRIBE RIDER RC.**

A. Rider RC is predicated upon a formula rate for developing the fixed costs associated with the Company's legacy generating assets that, under the Company's proposal, will effectively be dedicated to Ohio customers, as well as a reasonable rate of return for those assets. Through Rider RC, Duke Energy Ohio will recover the costs that are incurred in serving its customers with a reliable and adequate supply of capacity over the full term of the ESP. Additionally, to the extent the Company incurs costs to secure sufficient capacity to meet its reliability requirements, such costs would be incorporated into Rider RC. However, any third-party purchases necessary to meet the reliability requirement would be treated as an expense for determining the revenue requirement for Rider RC; so, there would be no return component for such market or third-party purchases. The Rider RC rate will be adjusted each year to reflect actual costs incurred, or changes in rate base as a result of environmental expenditures or other changes to the generating assets on which the rate is predicated.

The formula used to develop Rider RC has its roots in traditional ratemaking inasmuch as the Company incorporated many elements of the calculations it would make for determining the revenue requirement for its regulated gas and electric operations. The formula also incorporates a number of ratemaking concepts used by the Federal Energy Regulatory Commission (FERC) for its formula ratemaking for network integrated transmission service (NITS).[1]

Much like the formula used for setting the Company's NITS revenue requirement, the revenue requirement for Rider RC is based on actual, historic costs. All of the starting information used for the calculation begins with data from the FERC Form 1 Annual Report, a document which is publicly available. The formula includes a calculation of rate base, which in this case will be the rate base attributable to Duke Energy Ohio's Legacy Generating Assets.[2] In exchange for dedicating the assets to customers, the Company would seek a reasonable return on the rate base. The return would be based on an appropriate return on equity (ROE), as supported by Duke Energy Ohio witness Dr. Roger A. Morin, the average cost of debt for the most recent actual period, and the relative proportion of equity and debt making up the Company's capital structure.

The next step of the formula is to determine the expenses to be recovered. Eligible expenses include book depreciation expense, operating and maintenance

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[1] As a current member of the Midwest Independent System Operator, Inc. (Midwest ISO), Duke Energy Ohio annually updates its revenue requirement pursuant to a Midwest ISO formula rate, Attachment O, approved by the Federal Energy Regulatory Commission.
[2] See Direct Testimony of Salil Pradhan for a description of the Legacy Generating Assets.

(O&M) expense, property and other taxes, and income taxes on the equity portion of the return on rate base.

**Q. ARE ANY ADJUSTMENTS NECESSARY TO THE 'PER BOOKS' INFORMATION?**

A. Yes. A number of adjustments to the information contained in the Form 1 are necessary to determine the appropriate revenue requirement for Duke Energy Ohio's Legacy Generating Assets.

**Rate Base Adjustments:**

a. The values represented in the Form 1 for production plant include purchase accounting adjustments associated with the merger of Duke Energy and Cinergy Corp. in 2006. Purchase accounting is typically not allowed for recovery in conventional ratemaking; consequently, the impact of purchase accounting was removed from all plant and O&M accounts, and was also removed from the capital structure.

b. In April 2011, Duke Energy Ohio transferred its ownership stake in a number of gas-fired generation assets (often referred to as the DENA plants) that have never been used and useful for its retail customers. Because those assets are now owned by an affiliate and are not being dedicated to customers as part of the proposed ESP, the value of these assets indicated in the Form 1 for 2010 is removed from the Rider RC revenue requirement calculation along with all related expenses.

c. Duke Energy Ohio has common and general plant that supports its generation business and its other lines of business (*e.g.*, electric distribution, electric transmission, and gas distribution); consequently, some common and general plant is being allocated to Legacy Generation rate base in proportion to its relative net plant.

d. Applying conventional ratemaking principles commonly used before this Commission, the Rider RC formula deducts from rate base Legacy Generation's share of Accumulated Deferred Income Taxes (ADITs) and Accumulated Deferred Income Tax Credits (ADITCs). Some ADITs and ADITCs are clearly attributable to one line of business or another, while some are related to assets/expenses that cross more than one line of business. Because of the magnitude of ADITs, the schedules sponsored in Attachment WDW-1 include a detailed summary of each accounting record for this item and the allocation of those ADITs among the Company's lines of business.

e. To recognize the need for cash working capital, the FERC allows companies to estimate cash working capital needs by dividing non-fuel O&M expense by 8 (often referred to as the 45-day method). This methodology is often used in FERC rate cases and is a component of the formula rate for establishing the NITS revenue requirement.

**O&M Adjustments:**

a. Because the retail capacity rider is only intended to recover fixed costs, costs that are directly proportional to the number of MWh being generated (*i.e.*, variable costs) are excluded from the calculation. Consequently, expenses such as fuel expense, emission allowance (EA) expense, and environmental reagent expenses are eliminated.

b. All historic purchased power expense is eliminated; however, [redacted]

c. Certain O&M costs, particularly administrative and general (A&G) costs, support lines of business in addition to Legacy Generation. The bulk of these A&G costs are labor related; therefore, it is appropriate to allocate to Legacy Generation an amount of these costs in proportion to that line of business' share of overall salaries and wages. This is another common application of ratemaking principles and is consistent with the allocation methods used in our retail distribution rate cases in Ohio.

**Taxes**

a. Income taxes are included at the statutory effective rate and the calculation includes an adjustment to reflect the statutory level of Gross Domestic Production Tax Deduction under Section 199 of the Internal Revenue Code (Section 199 Deduction). Although the Section 199 Deduction can only be used if there is a positive taxable income for current taxes (as opposed to book income), ratemaking typically uses statutory rates for taxes and, because the

ESP, if approved, will ensure that Duke Energy Ohio will have positive book income, it is appropriate to include this benefit for customers.

b. Ohio no longer has a state income tax but, instead, has a commercial activities tax (CAT tax). The effect of this tax is included in the revenue requirement calculation.

c. Property and other taxes are included at the levels allocable to Legacy Generation for 2010.

**Q. PLEASE DESCRIBE HOW RIDER RC WILL BE UPDATED.**

A. As described above, the FERC-approved formula for establishing the revenue requirement for NITS allows for an annual update to the revenue requirement calculation shortly after the source of the data is available. Specifically, because the FERC formula uses the FERC Form 1 and this document is not publicly available until mid-April every year, the formula for calculating new transmission rates is updated in May each year, with rates becoming effective the next month.

In order to allow the Commission sufficient time to review the filing each year, the Company proposes that a filing be made each year on or before June 1 to update the revenue requirement and the rates for Rider RC. The Commission would have the opportunity to establish a formal review process and new rates would be updated upon a Commission order approving the rates for implementation by January 1 of the following year.

**Q. IS RIDER RC PROPOSED AS A NON-BYPASSABLE RIDER?**

A. Yes. In exchange for providing retail customers with virtually all of the value of the Legacy Generating Assets owned by Duke Energy Ohio and a fixed capacity charge that will not be subject to the market volatility that is discussed in the Direct Testimony of Duke Energy Ohio witnesses B. Keith Trent and Judah L. Rose, Rider RC will be unavoidable and thus applicable to all retail customers in Duke Energy Ohio's service territory. The Company's proposal to share most of the benefits of owning the generation (*e.g.*, profits on off-system sales, ancillary service revenue, etc.) is a major element of this proposal and it will also serve to mitigate any volatility that customers may experience in their price for electricity.

### B. <u>Rider PSM (Profit Sharing Mechanism)</u>

**Q. WHAT IS RIDER PSM?**

A. Rider PSM is a mechanism that will enable Duke Energy Ohio to credit back to customers most of the net profits derived from the Legacy Generating Assets. Most of this profit is derived from the sale of economic generation into the market. For example, when the market price of power exceeds the cost to the Company of generating that power, there will be a resulting margin (or profit) on the sale of this generation. Under the Company's ESP proposal, <u>all</u> of Duke Energy Ohio's economic generation will be available for dispatch into the market and <u>all</u> of the net profit derived from that market will be available for sharing between customers and the Company.

**Q. HOW WILL DUKE ENERGY OHIO MANAGE ITS PORTFOLIO OF ASSETS TO OPTIMIZE THE VALUE OF THIS GENERATION FOR CUSTOMERS?**

A. In many ways, the Company's management of Rider PSM will resemble its management of the current Rider PTC-FPP (fuel and purchased power rider). In both cases, the Company will have a portfolio of assets including coal, EAs, etc., that will be the basis for the costs of the products being sold in the market. There is a direct correlation between managing the portfolio of these assets and the value being created from these assets. Duke Energy Ohio witness Salil Pradhan discusses how the Company plans to manage the commodity positions (*e.g.*, fuel, emission allowances, etc.) and hedging strategy for Legacy Generating Assets, thereby creating the value for Rider PSM.

**Q. PLEASE DESCRIBE HOW RIDER PSM WILL BE UPDATED.**

A. For the initial rates being established in this ESP for 2012, Duke Energy Ohio will forecast the profits projected for sharing in Rider PSM for the entire year. That calculation will establish a baseline amount to be credited against Rider RC. Beginning with a March 1, 2012, filing, the Company will update Rider PSM based on updated forecasts for the upcoming full quarter (*i.e.*, April-June 2012 in the March 1 filing) and will reconcile the most recently completed prior quarter for actual data (*i.e.*, comparing the amount of profits to be shared for the quarter vs. how much was actually shared). In many ways, this process will mirror the current, quarterly filings for the existing Rider PTC-FPP.

The projected and reconciliation component of quarterly filings will include the revenue derived from ownership of the Legacy Generating Assets (*e.g.*, day-ahead and real-time sales in PJM, ancillary service revenue, etc.) and all variable costs (*e.g.*, fuel, EAs, reagent costs, etc.) incurred to generate the associated revenue.

**Q. DOES THE COMPANY PROPOSE A REVIEW PROCESS FOR RIDER PSM?**

A. Yes. On both a quarterly and annual basis, the Company proposes a review process that mirrors the current Rider PTC-FPP. The Company will file its quarterly update at least thirty days prior to the effective date of the new Rider PSM rates and, unless there is some intervention or Commission-ordered review, the new rates will become effective without the need for explicit Commission approval.

In the first quarter after each year the Rider PSM is in effect, the Commission will conduct an audit of the prior year's operation of Rider PSM. Much like the current annual audit for Rider PTC-FPP, the Commission may review the Company's management, policies, and practices for managing the asset portfolio and may review the financial data underlying the rate setting process for Rider PSM. The auditor would submit a report of its findings to the Commission and a formal review may be conducted. If the Commission engages an independent third-party auditor, those costs would be included, and netted against the customer share of amounts to be credited, in Rider PSM.

**Q. YOU MENTIONED EARLIER THAT THE EFFECT OF RIDER PSM WILL BE TO MITIGATE THE VOLATILITY RETAIL CUSTOMERS MAY EXPERIENCE IN THEIR OVERALL PRICE OF ELECTRICITY. PLEASE EXPLAIN WHAT YOU MEAN BY THAT.**

A. First of all, although distribution and transmission service would be part of an overall bill, the prices for these components are relatively stable. Principally, what

I am describing is the interaction between (1) the cost of service based price of capacity; (2) the availability of a market-based standard service offer exclusively for energy secured via an open auction process; and (3) the assignment of most of the value derived from the Legacy Generating Assets to all retail customers.

All involved in the retail and wholesale power markets are aware of how volatile the price of both capacity and energy has been. The Company's witnesses Trent and Rose discuss the volatility that has existed and will continue to exist in the markets for these products. The ESP being proposed by the Company is fundamentally designed to limit the volatility customers will see in electricity prices over an extended period of time. First, the cost-based capacity of the Legacy Generating Assets offers pricing stability to retail customers, which means customers will be exposed to little, if any, volatility in the market price for capacity. One has only to look at the outcome of the recent auction for capacity in PJM for evidence of how volatile the price for capacity can be. From planning year 2013/2014 to planning year 2014/2015, the market price set in PJM's auctions went from about $28 per MW-day to over $125 per MW-day. For planning year 2011/2012, the price was $110 per MW-day and, for planning year 2012/2013, the price was $16 per MW-day. This kind of volatility and instability in a major component of electric prices cannot be in the best interests of the Company, its customers, or the long-term economic growth of our region. Under the proposed ESP, most of the capacity needed to serve retail load will be from identified assets and priced to customers at an embedded cost, ensuring that Duke

Energy Ohio's retail customers will not see this type of volatility or instability in the price their capacity.

The market price of energy can also be quite volatile. The proposed ESP provides that all customers will pay a market price for energy, whether via a Standard Service Offer or when purchasing from competitive retail electric service (CRES) providers. However, the proposal to share virtually all of the net profits from Duke Energy Ohio's energy sales from its own Legacy Generation serves to mitigate the volatility in the overall price of generation. For example, without such a sharing mechanism, if retail energy prices were to escalate rapidly, customers would have to pay the rapidly escalating energy price as this type of market force would impact both the market-based SSO price and CRES providers' offers. However, with the sharing proposal and a properly managed portfolio of generation components (*e.g.*, fuel, EAs, etc.), higher energy prices should translate into higher profits for the Legacy Generating Assets. The net effect is that, while customers may pay higher energy prices in the market, these higher energy prices should translate into greater profits for Duke Energy Ohio's Legacy Generating Assets that will offset retail customers' overall generation price. Ultimately, the Company's proposal limits customers' exposure almost exclusively to the volatility in the underlying input prices for Duke Energy Ohio's Legacy Generating Assets, which, as discussed in the testimony of Duke Energy Ohio witness Salil Pradhan, can be effectively managed through portfolio optimization (or active management).

**Q. IS RIDER PSM PROPOSED AS A NON-BYPASSABLE RIDER?**

A. Yes. Because this rider is inexorably linked to Rider RC, it will be non-bypassable credit. Duke Energy Ohio's plan centers upon all customers in the footprint paying the non-bypassable charge for the stability offered by the Company's capacity. It is therefore reasonable that all customers also receive the proportional benefit those assets provide through Rider PSM.

### C. <u>Rider RE (Retail Energy)</u>

**Q. PLEASE DESCRIBE RIDER RE.**

A. The Company's proposed ESP decouples capacity from energy. The Company will be the single source of capacity for all retail customers and the market will be the exclusive provider of energy for retail customers. Toward that end, the Company will procure 100 percent of its retail energy requirement via a competitive bid process, as detailed in the Direct Testimony of Duke Energy Ohio witness Robert J. Lee. As proposed by Mr. Lee, such wholesale auctions generally will be conducted two times per year[3] for the duration of the ESP and, after the approval process is complete, the results of the auctions will be converted into retail rates for Duke Energy Ohio's SSO customers. The Company's proposed Rider RE (Retail Energy) will be the vehicle for transforming the results of the auction into retail rates. Duke Energy Ohio witness Jeffrey R. Bailey discusses the process for converting the wholesale rates to retail rates, for recovery through Rider RE.

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[3] During 2011, there will be only one auction, as there would be insufficient time for two auctions.

The Company also proposes to recover through Rider RE prudently incurred costs associated with conducting the auctions pursuant to its CBP plan. And, in the event a supplier defaults, Duke Energy Ohio proposes to recover, through Rider RE, the net costs incurred by it to provide SSO service. The net costs would be those unrecovered costs remaining after the Company reasonably pursues contractual remedies against the defaulting supplier.

**Q. PLEASE EXPLAIN THE COMPANY'S CONTIGENCY PLAN TO PROCURE WHOLESALE ENERGY FOR DELIVERY BEGINNING JANUARY 1, 2012, IF IT IS UNABLE TO CONDUCT AN AUCTION IN 2011 AND THE COST RECOVERY MECHANISM FOR THIS PLAN.**

A. *As described by Duke Energy Ohio witnesses Robert J. Lee and James S.* Northrup, the Company proposes to conduct wholesale energy auctions for its SSO load, with delivery beginning on January 1, 2012. In the event a Commission order approving the proposed ESP is not issued in sufficient time to enable the first auction to be conducted in time to meet that goal, Duke Energy Ohio proposes to procure the energy necessary to serve its load via the PJM Spot Energy Market, for whatever period is necessary as a result of the delay. Costs for the acquisition of this energy will be recovered through Rider RE.

**Q. PLEASE EXPLAIN HOW RIDER RE WILL BE UPDATED.**

A. Within thirty days of the conclusion of each auction for SSO load, the Company will make a filing with the Commission detailing the process of converting the results of the auction into retail rates. In addition to recovering the cost of supplier-provided energy, the Company will seek to recover the costs of conducting the auction including, but not limited to, the cost of consultants hired by the Commission to review the auction process and the direct costs of conducting the auction. Further, Rider RE will be used to reconcile the rates charged to customers with the amounts paid to wholesale suppliers.

**Q. IS RIDER RE PROPOSED AS A NON-BYPASSABLE RIDER?**

A. No. Rider RE reflects the Company's SSO energy price and, as such, is unconditionally avoidable by shopping customers.

**D. <u>Rider AER-R (Alternative Energy Resource Requirement)</u>**

**Q. PLEASE DESCRIBE RIDER AER-R.**

A. Rider AER-R is being proposed to recover the Company's costs for complying with the Ohio's renewable energy requirements. The responsibility for procuring renewable energy certificates (RECs) generally follows the load obligation, although the nexus is slightly convoluted insofar as the REC obligation is based on the average of the prior three years' of load rather than the current load obligation.[4] Taken to its extreme, this requirement could mean a supplier of retail energy, whether it is the electric distribution utility or a CRES provider, could have an obligation to supply RECs if it served <u>any</u> load in the prior three years, even if it has no load to serve in the current year.

**Q. PLEASE EXPLAIN HOW RIDER AER-R WILL BE UPDATED.**

A. The rider will be filed quarterly and will include true-up provisions.

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[4] O.A.C. 4901:1-40-03(B)(1).

**Q. IS RIDER AER-R PROPOSED AS A NON-BYPASSABLE RIDER?**

A. No. Pursuant to R.C. 4928.64(E) costs to comply with the alternative energy resource requirements must be bypassable. Consequently, Rider AER-R is an unconditionally avoidable charge.

### E. Rider RECON (Reconciliation)

**Q. PLEASE DESCRIBE RIDER RECON.**

A. Rider RECON is intended to true up Duke Energy Ohio's current Rider PTC-FPP (fuel and purchased power) and Rider SRA-SRT (system reliability tracker), both of which will expire upon the effective date of the ESP proposed in the Company's Application. It is a near certainty that both of those riders will have a balance of over- or under-recovery as of December 31, 2011. The purpose of Rider RECON, therefore, is to true up the collective balance of any over- or under-recovery for these two existing riders. To the extent the sum of the balances of over-/under-recovery for the two riders is an over-recovery, Rider RECON will be a credit to non-shopping customers. If the cumulative balance is an under-recovery, Rider RECON will be a charge to non-shopping customers. Because the balance of over-/under-recovery for Rider RECON is expected to be relatively small, the anticipated duration of Rider RECON is short – Duke Energy Ohio will be able to resolve any over- or under-recoveries within six months of the new ESP. And once that resolution occurs, Rider RECON will expire. It should also be noted that, because the magnitude of Rider RECON is expected to be relatively small and the duration of recovery is expected to be relatively short, the Company is proposing that no carrying costs be included in the rider. This is reasonable particularly in light of the fact that there are no carrying charges associated with either Rider PTC-FPP or Rider SRA-SRT that are being reconciled in the proposed Rider RECON.

Q. **WHEN WILL RIDER RECON BE IMPLEMENTED?**

A. As discussed above, the riders being trued up via Rider RECON are proposed to end on December 31, 2011. Because it will take some time to determine the actual results (*i.e.*, revenue and costs) for the period in question, the Company anticipates making a filing on or before March 1, 2012, to establish Rider RECON. Absent any objection from the Commission or intervenors, the rider will go into effect on April 1, 2012. Depending on the magnitude of the amount to be reconciled, the duration of Rider RECON could be up to six months.

Q. **RIDERS PTC-FPP AND SRA-SRT ARE SUBJECT TO ANNUAL AUDITS. WILL THAT AFFECT YOUR PROPOSAL REGARDING RIDER RECON?**

A. In prior Commission audits of these two riders, the Commission has ordered Duke Energy Ohio to exclude a cost that had previously been recovered. Because the twelve-month period ending December 31, 2011, is also subject to an annual audit, which will not be conducted until early in 2012, the Company proposes to use Rider RECON to address any Commission-ordered refunds or charges stemming from the audit review process.

Q. **IS RIDER RECON PROPOSED AS A NON-BYPASSABLE RIDER?**

A. Rider RECON is being proposed as an unconditionally bypassable rider.

### F. Rider UE-GEN (Uncollectible Generation Expense)

**Q. PLEASE EXPLAIN RIDER UE-GEN.**

A. Duke Energy Ohio is proposing to recover the cost of bad debt associated with its SSO service, via Rider UE-GEN. The Company currently has an approved rider to recover costs of bad debt associated with distribution service (Rider UE-ED[5]) and bad debt related to retail transmission is a component of the FERC-approved formula rates for calculating the NITS revenue requirement that is recoverable through Rider BTR.[6] However, there is no existing rider mechanism to recover the bad debt expense associated with serving SSO load, therefore, the Company, proposes to implement Rider UE-GEN for that purpose.

Additionally, Duke Energy Ohio proposes to modify its existing Purchase of Accounts Receivable (PAR) program, with such modifications enabling the recovery of the bad debt associated with CRES providers' accounts receivable.

As I understand, Duke Energy Ohio is the only electric distribution utility (EDU) in Ohio that purchases accounts receivable on any terms from CRES providers. Under the current structure and pursuant to prior Commission approval, CRES providers must be enrolled in the Company's PAR program in order to have their accounts receivable purchased at a discounted rate. Although the current structure has aided CRES providers and, by extension, the competitive retail market, there are improvements that can be made to the scope of this

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[5] "UE-ED" means "uncollectible expense – electric distribution."

[6] The Commission approved the Company's Application to implement Rider BTR on May 6, 2011, in Case No. 11-2641-EL-RDR.

purchase of accounts receivable program that, if properly implemented, will benefit both CRES providers and the Company.

Here, Duke Energy Ohio is proposing to align the purchase of electric generation accounts receivable from CRES providers with its purchase of natural gas accounts receivable. Under this proposal, the Company will purchase electric generation accounts receivable at no discount, remitting payment on the twentieth day of the month after which billing occurs. Duke Energy Ohio will recover the uncollectible generation expense associated with all generation accounts – its own and those purchased from CRES providers – via Rider UE-GEN.

**Q. WILL RIDER UE-GEN BE A NON-BYPASSABLE RIDER?**

A. Yes. Given that it extends to the uncollectible expense of all customers – shopping and non-shopping – the rider must be non-bypassable.

**Q. HAS THE COMMISSION RECENTLY OFFERED AN OPINION REGARDING A RIDER LIKE UE-GEN?**

A. Yes. A similar rider was discussed as part of Duke Energy Ohio's request for approval of a Market Rate Offer (MRO) in Case No 10-2586-EL-SSO.

Specifically, in its February 23, 2011, Order, the Commission held:

> In considering the proposed creation of Rider UE-GEN, the Commission is mindful that, as proposed by Dominion and RESA, as an unavoidable rider. Rider UE-GEN furthers state policy by promoting competition. Specifically, if Duke purchases accounts receivable at no discount, this will likely increase CRES providers' usage of Duke's billing service. Additionally, greater access to consolidated billing for CRES providers, without a purchase of accounts receivable discount, creates a level playing field and allows greater freedom for customer shopping without undergoing a second credit evaluation by a CRES provider, thus promoting shopping among low-income consumers. Therefore, the Commission would support the creation of Rider UE-GEN as an

> unavoidable rider, designed to recover bad debt associated with customers taking generation service through the SSO and from CRES providers. Moreover, the Commission recognizes that if Duke recovered Rider UE-GEN consistent with the process set forth by Duke in its reply brief, it would resolve any issues regarding Duke's PAR.

### G. Rider DR (Distribution Reliability)

**Q. PLEASE EXPLAIN RIDER DR.**

A. Rider DR, as proposed in the Application, is intended to recover incremental capital investment for distribution-related reliability investment that is not otherwise recovered through base rates, and a rate of return. Rider DR would thus be used as a mechanism for all distribution upgrades, including the Company's current SmartGrid deployment program. The incremental revenue requirement applicable to Rider DR would be determined by subtracting from the current distribution cost of service the revenue that is recovered through base rates.

The proposed Rider DR incorporates a decoupling mechanism, thereby reducing any disincentive that an EDU may have to promote energy efficiency programs. In this regard, Rider DR will recover the difference between the actual base distribution revenue and adjusted based distribution revenue, where:

Actual Base Distribution Revenue = Actual Base Distribution Revenue for Each Rate Schedule

Adjusted Base Distribution Revenue = Annual Base Distribution Revenue for Each Rate Schedule Approved in the Most Recent Case, Adjusted for Changes in Billing Determinants

**Q. WHAT IS THE RATE OF RETURN THAT WOULD BE APPLICABLE TO THE INCREMENTAL CAPITAL INVESTMENT RECOVERED VIA RIDER DR?**

A. The rate of return would be equal to the rate of return approved in the Company's most recent electric distribution rate case, which is 10.63 percent.

**Q. WHY WOULD YOU USE AN ROE RATE FOR RIDER DR THAT IS DIFFERENT THAN WHAT DR. MORIN IS PROPOSING FOR CALCULATING RIDER RC?**

A. The purpose of Rider DR is limited to tracking the change in "distribution"-related investment and "distribution"-related O&M. Duke Energy Ohio and all investor-owned utilities in Ohio operate unbundled businesses. Rates for distribution, transmission, and generation are set at different times, potentially from different regulatory agencies (*i.e.*, the ROE for transmission investment is set by the FERC), and based on different assessments of risks. Because Rider DR is addressing only the distribution business, it is appropriate to use the most recent ROE established for that line of business. The ROE advocated in this proceeding by Dr. Morin is for the Company's generation business; so, it is not unexpected that the ROE for generation and distribution business would be different.

**Q. IF RIDER DR IS APPROVED, WILL THE COMPANY CONTINUE SEEKING RECOVERY OF ITS SMARTGRID INVESTMENT THROUGH RIDER DR-IM?**

A. No. If Rider DR is approved, the Company will make no future filings for recovery of SmartGrid investments via Rider DR-IM. Virtually all of the SmartGrid investment is related to the operation of an electric distribution system. In many ways, the SmartGrid program mirrors another very successful capital improvement program currently underway for the Company's gas operations. In that program, the accelerated main replacement program (AMRP), the Company invested a significant amount of capital in its gas distribution system. The Commission approved a rider (Rider AMRP) for the Company to recover the costs of the program and, since the program began in 2001, the Company has had two base rate cases for gas service. In both rate cases, the then existing AMRP investment was "rolled-in" to base rates. When the Company files its next general rate case for electric distribution, it will make the same proposal for its SmartGrid investment.

In the Company's view, SmartGrid investment should be included in Rider DR because it is designated as distribution investment and virtually all of the costs and savings are distribution-related. Also, because it is an investment that would be rolled into distribution base rates, it follows that it should be treated like all other distribution investment for purposes of establishing Rider DR. Duke Energy Ohio witness Mark Wyatt provides testimony regarding the Company's distribution infrastructure investment, including a discussion of the SmartGrid program.

**Q. WILL RIDER DR RECOVER ONLY INCREMENTAL COSTS?**

A. No. To the extent there are benefits associated with a particular initiative or event, customers would more quickly realize those benefits under the proposed Rider DR. A conspicuous example of a cost reduction that would flow through Rider DR is any savings in distribution-related property taxes. Duke Energy Ohio is currently engaged in an appeal process to reduce its property taxes. If successful, a significant portion of any property tax reduction would be related to distribution investment. Rider DR would provide a vehicle to pass any realized savings on to customers in short order. Absent a vehicle such as Rider DR, customers would not see the benefit of a property tax reduction until the next distribution rate case.

Q. **IS DUKE ENERGY OHIO PROPOSING TO RECOVER INCREMENTAL OPERATING AND MAINTENANCE EXPENSE THROUGH RIDER DR?**

A. Yes. Again, to the extent the costs are distribution-related, the proposal is to compare the current year costs to comparable costs as approved in current rates. Duke Energy Ohio witness James E. Ziolkowski provides a detailed explanation of the rider and an estimate of the rider rates during the ESP.

Q. **IS RIDER DR PROPOSED TO BE A NON-BYPASSABLE RIDER?**

A. Yes. Rider DR addresses distribution issues and, hence, relates to all customers, whether they purchase energy from Duke Energy Ohio or from a competitive supplier.

### H. <u>Riders Unchanged by the ESP</u>

Q. **IS THE COMPANY PROPOSING ANY CHANGES TO ITS COST RECOVERY FOR MEETING ENERGY EFFICIENCY TARGETS IN THIS CASE?**

A. Not at this time. Until further notice, the Company will continue to use its Rider SAW-R (save-a-watt Rider) to recover the cost of complying with the state's energy efficiency mandates.

Q. **IS THE COMPANY PROPOSING ANY CHANGES TO ITS ECONOMIC COMPETITIVENESS FUND RIDER?**

A. No. The Company is not intending to alter its current Rider ECF (economic competitiveness fund rider). However, as detailed in the Direct Testimony of Julia S. Janson, Duke Energy Ohio is proposing to create a new program focused on economic development in southwest Ohio.

**Q. PLEASE EXPLAIN HOW THE COMPANY'S PROPOSED NEW ECONOMIC DEVELOPMENT PROGRAM WILL BE FUNDED.**

A. As discussed above, a percentage of the net profits derived from ownership of the Legacy Generating Assets (*e.g.*, energy sales) will be credited back to customers through Rider PSM. Similarly, a percentage of the net profits will be allocated Duke Energy Ohio. The Company is proposing that a portion of these profits, otherwise allocated to customers and the Company, will fund the proposed new economic development program. Specifically, the Company's proposal is to share the net profits such that 80 percent of the net profits benefit customers and 20 percent benefit the Company. Of each share, 5 percent will support the new economic development program.

As described by Duke Energy Ohio witness Janson, Advance Southwest Ohio will be a program to provide financial support for economic development, retention, and expansion in targeted southwest Ohio regional clusters. This program will be funded with 5 percent of the customers' 80 percent portion of net profits from energy and ancillary services sales and 5 percent of the Company's 20 percent portion of such profits. These funds will be provided directly to Advance Southwest Ohio such that the amount credited to customers through Rider PSM is the remaining 76 percent of the net profits. The expenditure of these funds will be controlled, as discussed by witness Janson, by the Company, with the approval of the Chairman of the Commission as to expenditures of the monies supplied by the customers.

The funding for Advance Southwest Ohio will not be based on any tariff. Instead, the process of computing the Rider PSM credit will address the funding of the programs.

## I. <u>Summary of ESP Riders</u>

**Q. WOULD YOU SUMMARIZE THE VARIOUS RIDERS THAT CUSTOMERS WILL BE SUBJECT TO DURING THE ESP?**

A. Under the Company's proposal, the only significant difference in the riders applicable to retail customers is whether the customer is a shopper or a non-shopper. The proposed ESP is a considerably simpler model in that regard.

**Table 3 - Riders Applicable to Non-Shopper and Shopper**

| **Non-Shopper** | | **Shopper** |
|---|---|---|
| **Generation Riders** | | **Generation Riders** |
| Rider RC | | Rider RC |
| Rider PSM | | Rider PSM |
| *Rider RE (bypassable)* | ➔ | CRES Offer (Energy + AER + Market-Based RTO costs) |
| *Rider AER-R (bypassable)* | | |
| Rider UE-GEN | | Rider UE-GEN |
| *Rider RECON (bypassable)* | | |
| | | |
| **Transmission Riders** [a] | | **Transmission Riders** [a] |
| Rider BTR | | Rider BTR |
| *Rider RTO (bypassable)* | | |
| | | |
| **Distribution Riders** | | **Distribution Riders** |
| Rider SAW-R | | Rider SAW-R |
| Rider DR | | Rider DR |
| Rider ECF | | Rider ECF |

Note: [a] The Company is not seeking approval of transmission cost recovery in this proceeding. Transmission riders are shown here for purposes of comparing charges for shopping and non-shopping customers.

## III. PROVISIONS FOR TESTING THE ESP AND TRANSITIONAL CONDITIONS SHOULD THE ESP BE TERMINATED

**Q. IS DUKE ENERGY OHIO RECOMMENDING PROVISIONS FOR TESTING ITS PROPOSED ESP?**

A. Yes. Pursuant to R.C. 4928.143(B)(1), an ESP having a term longer than three years may include provisions permitting the Commission to test the plan, as required under Section (E) of R.C. 4928.143. Additionally, the ESP may include transitional conditions should the Commission elect to terminate the ESP and migrate to the MRO as a result of the required testing under Section (E).

**Q. WHAT ARE THE PROVISIONS THAT THE COMPANY IS PROPOSING FOR TESTING THE PLAN?**

A. R.C. 4928.143(E) sets forth two prospective tests that must be conducted in respect of any ESP having an approved term longer than three years. Specifically, the law requires that, in year four and every fourth year thereafter, the Commission:

> [D]etermine whether the plan, including its then-existing pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, continues to be more favorable in the aggregate and during the remaining term of the plan as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code.

Additionally, the Commission is to determine whether the prospective effect of the ESP is "substantially likely" to provide the Company with significantly excessive earnings.

Thus, there are two aspects of the prospective testing of the ESP to be conducted by the Commission – an "in the aggregate" test and a significantly excessive earnings test. I identify the recommended provisions for both aspects of the testing below.

## A. Prospective "In the Aggregate" Test

**Q. PLEASE IDENTIFY THE PROVISIONS FOR CONDUCTING THE "IN THE AGGREGATE" TEST UNDER R.C. 4928.143(E).**

A. The ESP must be compared against the expected results under R.C. 4928.142 and, as Duke Energy Ohio owned generating assets as of July 31, 2008, it is subject to a blending requirement under the MRO provisions. As the Commission has previously opined, R.C. 4928.142(D) contemplates a default blending period of 10 percent market bid in year, 20 percent in year two, 30 percent in year three, 40 percent in year four, 50 percent in year five, and 100 percent after year five.

As of the fourth year of the ESP, the Company will not have previously filed an MRO and, consequently, this blending criterion is applicable when comparing Duke Energy Ohio's ESP and the expected results under R.C. 4928.142. Accordingly, for purposes of establishing the expected results under R.C. 4928.142, Duke Energy Ohio proposes, with respect to the year-four test, that the MRO pricing be based upon the following percentages, for each relevant year of the comparison:

**Table 4 - MRO Blending Percentages**

| Year of ESP | Market | Most Recent ESP |
|---|---|---|
| 4 | 10% | 90% |
| 5 | 20% | 80% |
| 6 | 30% | 70% |
| 7 | 40% | 60% |
| 8 | 50% | 50% |
| 9+ | 100% | 0% |

The "most recent ESP" at the time of the first test, as referenced in the table above, is comprised of the retail rates for Rider RC, as offset by Rider PSM, and Rider RE as of May 31, 2015, and the "market" reflects the projected market prices for capacity and energy at the time of the comparison.

Duke Energy Ohio proposes that, at the time such a comparison is made, the forecasted prices resulting from the MRO blending percentages identified above be compared to Company's projected Rider RC rates at that time, as off-set by Rider PSM, and the projected Rider RE rates for the period between June 1, 2015, and May 31, 2021.

The "in the aggregate" test contemplates a comparison of all of the terms and conditions of the ESP against with the expected results under R.C. 4928.142. Accordingly, when determining whether the ESP remains more favorable than the expected results under the MRO provisions. Duke Energy Ohio witness Trent summarizes these other considerations. Notably, however, consideration must be given to the benefits derived from, among other things, creating and funding economic development via Advance Southwest Ohio contrasting with the absence of a similar program and dollars for economic development that would not exist under the MRO structure.

But a comparison of costs necessary to comply with Ohio's alternative energy resource (AER) requirements would be an unnecessary exercise as both Duke Energy Ohio and CRES providers have the same obligation. Furthermore, Rider AER-R or something similar would exist in either an ESP or an MRO and would recover the same costs inasmuch as the obligations for alternative energy are independent of the structure of Company's retail generation business (*i.e.*, MRO vs. ESP). Ultimately, the costs to comply with the AER requirements should be largely the same, whether incurred by Duke Energy Ohio or reflected in CRES providers' offers, or whether the Company is operating under an MRO or an ESP. Thus, projections related to Rider AER-R should be excluded from the review.

The same analysis should be conducted in year eight of the ESP, revised only to adjust the blending percentages. Again, as no MRO will have been filed by the eighth year of the Company's ESP, the blending percentages for that eighth year must be 10 percent market/90 percent most recent ESP. And the percentages applicable to the ninth year necessarily would be 20 percent market/80 percent most recent ESP. Here, the "most recent ESP" price would be comprised of the retail rates for Rider RC, as offset by Rider PSM, and Rider RE as of May 31, 2019.

**Q. IS THE COMPANY PROPOSING TO ADJUST THE "MOST RECENT ESP" PRICE FOR PURPOSES OF TEST UNDER R.C. 4928.143(E)?**

A. Yes. The comparison is of the proposed ESP to the "expected results that would otherwise apply under section 4928.142." Because R.C. 4928.142(D) (*i.e.*, the MRO statute) provides that the most recent ESP price can be adjusted for such things as fuel, purchased power, and environmental costs, the Legacy ESP price used in the blending is adjusted for projected changes in these costs for as long as the blending occurs.

### B. Prospective Significantly Excessive Earnings Test

**Q. PLEASE IDENTIFY THE PROVISIONS FOR CONDUCTING THE SIGNIFICANTLY EXCESSIVE EARNINGS TEST UNDER R.C. 4928.143(E).**

A. R.C. 4928.143(E) also requires the Commission to determine, in year four and every fourth year thereafter, whether the prospective effect of the Company's proposed ESP is substantially likely to lead to significantly excessive earnings. Pursuant to this statutory requirement, therefore, the Commission must ascertain the substantial likelihood of Duke Energy Ohio significantly over-earning from June 1, 2015, through the termination of the ESP on May 31, 2021. Again, a similar test will be conducted for the period of June 1, 2019, through May 31, 2021. In administering this test, Duke Energy Ohio recommends the following methodology.

For purposes of this calculation, Duke Energy Ohio will use calendar year projections. At the time of the first test, the Company will provide a projection of earnings from its electric operations for each year through 2021 (only for purposes of applying this test, it is assumed that the proposed ESP at the end of 2021 rather than May 31, 2021). The financial statements supporting this calculation will include an income statement and balance sheet for Duke Energy Ohio's electric operations. To calculate the projected return on equity, the Company will start with Net Income and make the following adjustments, if necessary:

- Eliminate all depreciation and amortization expense and impairment charges related to the purchase accounting recorded pursuant to the Duke Energy/Cinergy Corp. merger and post-merger impacts to retained earnings;
- Eliminate all impacts of refunds to customers pursuant to R.C. 4928.143(E);
- Eliminate all impacts of mark-to-market accounting;
- Eliminate all impacts of material, non-recurring gains or losses, including but not limited to, the sale or disposition of assets;
- Eliminate all impacts of parent, affiliated, or subsidiary companies and, to the extent reasonably feasible and prudently justified in the opinion of Duke Energy Ohio, eliminate the impacts of its natural gas distribution business.

The adjusted net income will be divided by Common Equity to determine the resulting ROE. Certain adjustments will be made to Common Equity.

- Eliminate the acquisition premium recorded to equity pursuant to the Duke Energy/Cinergy Corp. merger.
- Eliminate the cumulative effect of the Net Income adjustments.

If the projected annual return on ending common equity for the relevant years, as adjusted pursuant to the above, is 50 percent higher[7] than the ROE used

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[7] *See In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Administration of the Significantly Excessive Earnings Test under Section 4928.143(F), Revised Code, and Rule 4901:1-35-10, Ohio Administrative Code*, Case No. 10-1261-EL-UNC, Opinion and Order at pages 20, 24-25 (January 11, 2011).

for calculating Rider RC, there is a substantial likelihood that the Company will have "significantly" excessive earnings. However, the Commission's reviews in year four and year eight do not obligate the Company to refund any monies to customers as a result of a prospective earnings test. Rather, should the Commission determine that the Company's ESP is no longer better, in the aggregate, than the expected results under R.C. 4928.142 or that there is a substantial likelihood that Duke Energy Ohio will, prospectively, have significantly excessive earnings under the ESP, the Commission can only then decide whether to terminate the then-current ESP.

**Q. ARE THERE ANY OTHER ASPECTS TO THE REVIEWS CONTEMPLATED FOR YEARS FOUR AND EIGHT OF THE ESP?**

A. As Rider RC is largely predicated upon costs to serve and a rate of return, it would be reasonable, in the context of the year-four and year-eight reviews, to ascertain whether any adjustment (increase or decrease) to the ROE rate is appropriate. Because the required ROE may change for a variety of factors, including general economic conditions, changes in risk profiles, etc., the Commission, any intervenor, or the Company may, at the time of the review, offer testimony regarding changes to the ROE used for calculating Rider RC. If no party files testimony supporting a new ROE at that time, the then-current, approved ROE will persist until the next review. If a party does file testimony in support of a new ROE, all parties would have an opportunity to respond by filing rebuttal testimony and the Commission would determine, based on the filed evidence, an appropriate ROE for future calculations of Rider RC.

**Q. IS DUKE ENERGY OHIO PROPOSING A PARTICULAR DATE BY WHICH THE REVIEWS IN YEAR FOUR AND YEAR EIGHT WOULD BE INSTITUTED?**

A. On or before January 1, 2015, the Company will make a filing with the Commission with all relevant material upon which the Commission may rely in evaluating whether the ESP continues to be better, in the aggregate, than an MRO. The Company will make another filing on or before January 1, 2019, for the next review.

**Q. IF THE COMMISSION SHOULD DECIDE TO TERMINATE THE ESP AS A RESULT OF THE REVIEW PURSUANT TO R.C. 4928.143(E), WHAT ARE THE TRANSITIONAL CONDITIONS THAT THE COMPANY PROPOSES?**

A. Assuming the Commission would terminate the proposed ESP before it expired on May 31, 2021, it must have made a determination that the ESP was no longer "better in the aggregate" than the MRO or that continuation of the ESP will result in significantly excessive earnings. Thereafter, the Commission will have to determine whether to terminate the plan and migrate Duke Energy Ohio to the alternate MRO structure. It is not possible to predict at this time, what course the Commission may prescribe. Therefore, until the Commission approves an alternative SSO, the Company would operate under the terms of the ESP that exists at that time. Inasmuch as the transition of the proposed ESP to an MRO would affect the auction schedule and products included in the auctions, Duke Energy Ohio proposes some transitional conditions in its application. Company witness Lee speaks to these conditions. However, Duke Energy Ohio expressly reserves the right to recommend additional conditions for an orderly transition, should the Commission require the Company to provide a SSO in the form of an MRO.

## IV. <u>GOVERNMENTAL AGGREGATION</u>

**Q. WHAT IS GOVERNMENTAL AGGREGATION?**

A. Governmental aggregation is a process by which municipalities, townships, or counties may negotiate for rates for the collective load of the non-mercantile customers in the area. Thus, the loads of the residents are aggregated for improved negotiating leverage. Governmental aggregation is provided for in R.C. 4928.20.

**Q. WHAT IS REQUIRED BY DIVISION (I) OF REVISED CODE 4928.20?**

A. The words of division (I) of that statute read as follows:

> Customers that are part of a governmental aggregation under this section shall be responsible only for such portion of a surcharge under section 4928.144 of the Revised Code that is proportionate to the benefits, as determined by the commission, that electric load centers within the jurisdiction of the governmental aggregation as a group receive. The proportionate surcharge so established shall apply to each customer of the governmental aggregation while the customer is part of that aggregation. If a customer ceases being such a customer, the otherwise applicable surcharge shall apply. Nothing in this section shall result in less than full recovery by an electric distribution utility of any surcharge authorized under section 4928.144 of the Revised Code.

The words of R.C. 4928.144, referenced in division (I), read as follows:

> The public utilities commission by order may authorize any just and reasonable phase-in of any electric distribution utility rate or price established under sections 4928.141 to 4928.143 of the Revised Code, and inclusive of carrying charges, as the commission considers necessary to ensure rate or price stability for

consumers. If the commission's order includes such a phase-in, the order also shall provide for the creation of regulatory assets pursuant to generally accepted accounting principles, by authorizing the deferral of incurred costs equal to the amount not collected, plus carrying charges on that amount. Further, the order shall authorize the collection of those deferrals through a nonbypassable surcharge on any such rate or price so established for the electric distribution utility by the commission.

**Q. WHAT IS REQUIRED BY DIVISION (J) OF REVISED CODE 4928.20?**

A. The words of division (J) of that statute read as follows:

On behalf of the customers that are part of a governmental aggregation under this section and by filing written notice with the public utilities commission, the legislative authority that formed or is forming that governmental aggregation may elect not to receive standby service within the meaning of division (B)(2)(d) of section 4928.143 of the Revised Code from an electric distribution utility in whose certified territory the governmental aggregation is located and that operates under an approved electric security plan under that section. Upon the filing of that notice, the electric distribution utility shall not charge any such customer to whom competitive retail electric generation service is provided by another supplier under the governmental aggregation for the standby service. Any such consumer that returns to the utility for competitive retail electric service shall pay the market price of power incurred by the utility to serve that consumer plus any amount attributable to the utility's cost of compliance with the alternative energy resource provisions of section 4928.64 of the Revised Code to serve the consumer. Such market price shall include, but not be limited to, capacity and energy charges; all charges associated with the provision of that power supply through the regional transmission organization, including, but not limited to, transmission, ancillary services, congestion, and settlement and administrative charges; and all other costs incurred by the utility that are associated with the procurement, provision, and administration of that power supply, as such costs may be approved by the commission. The period of time during which the market price and alternative energy resource amount shall be so assessed on the consumer shall be from the time the consumer so returns to the electric distribution utility until the expiration of the electric security plan. However, if that period of time is expected to be more than two years, the commission may reduce the time period to a period of not less than two years.

The words of division (B)(2)(d) of R.C. 4928.143, referenced in that section, read as follows, with the lead-in information of division (B)(2):

> The plan may provide for or include, without limitation, any of the following:
>
> (d) Terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service;

R.C. 4928.64, referenced in division (J), addresses the provision, by an electric distribution utility, of electricity from alternative energy resources.

**Q. WHAT IS REQUIRED BY DIVISION (K) OF REVISED CODE 4928.20?**

A. The words of Division (K) read as follows:

> The commission shall adopt rules to encourage and promote large-scale governmental aggregation in this state. For that purpose, the commission shall conduct a immediate review of any rules it has adopted for the purpose of this section that are in effect on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008. Further, within the context of an electric security plan under section 4928.143 of the Revised Code, the commission shall consider the effect on large-scale governmental aggregation of any nonbypassable generation charges, however collected, that would be established under that plan, except any nonbypassable generation charges that relate to any cost incurred by the electric distribution utility, the deferral of which has been authorized by the commission prior to the effective date of the amendment of this section by S. B. 221 of the 127th general assembly, July 31, 2008.

**Q. HOW DOES DUKE ENERGY OHIO INTEND TO ADDRESS GOVERNMENTAL AGGREGATION PROGRAMS AND IMPLEMENTATION OF DIVISION (I) OF REVISED CODE 4928.20?**

A. As I understand based upon advice of counsel, Duke Energy Ohio is not, in this Application, seeking any deferral or phasing in of deferrals, as authorized under R.C. 4928.144. Thus, the provisions of R.C. 4928.20(I) are not applicable to the Company's proposed ESP. And to the extent R.C. 4928.20(I) is intended to assist governmental aggregators, the Company's ESP will not impede that intent.

**Q. HOW DOES DUKE ENERGY OHIO INTEND TO ADDRESS GOVERNMENTAL AGGREGATION PROGRAMS AND IMPLEMENTATION OF DIVISION (J) OF REVISED CODE 4928.20?**

A. As I understand, based upon advice of counsel, the provisions of R.C. 4928.20(J) that concern a charge for standby service are also not applicable to the Company's ESP Application. Duke Energy Ohio is not proposing any charge for providing standby service. Accordingly, the implementation of R.C. 4928.20(J) is not complicated by the Company's proposed ESP.

**Q. HOW DOES DUKE ENERGY OHIO INTEND TO ADDRESS GOVERNMENTAL AGGREGATION PROGRAMS AND IMPLEMENTATION OF DIVISION (K) OF REVISED CODE 4928.20?**

As I understand, based upon advice of counsel, R.C. 4928.20(K) provides instruction to the Commission in promulgating rules to "encourage and promote large-scale governmental aggregation" in Ohio. As this instruction is directed to the Commission, Duke Energy Ohio's ESP is necessarily irrelevant to implementation of certain parts of R.C. 4928.20(K). That is, the Company's filing is not one that will result in rules designed to encourage or promote aggregations.

R.C. 4928.28(K) also directs the Commission to consider the effect of any non-bypassable generation charge on large-scale aggregation, with the exception of non-bypassable charges for which a deferral was created prior to the effective date of SB 221. Again, compliance with this statutory provision requires conduct by the Commission. But to assist the Commission in its consideration, Duke Energy Ohio submits that its proposed ESP will not impede the formation of large-scale governmental aggregations. Rather, the competitive retail market should be more robust under the Company's proposal. All retail load will pay a market price for energy. The proposed ESP removes a perversion that exists in the current ESP where one provider, namely Duke Energy Ohio, must provide energy and capacity at a non-competitive rate while all other providers compete at market rates. The Company's proposed ESP is designed to remove that disconnect. No provider, including Duke Energy Ohio, has a competitive advantage or disadvantage in pricing its product, energy in this case, to retail load, whether it is an aggregated load or its is on an individual customer basis.

An additional benefit of the proposed ESP is the long-term nature of the plan. To date, no utility has offered any ESP that lasts longer than three years. In fact, the most recent application for an ESP filed by AEP-Ohio[8] is shorter still at only twenty-nine months. It is difficult for the utility, CRES providers, and customers – and for aggregations – to operate with any degree of long-term

[8] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to 4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan,* Case No. 11-348-EL-SSO, *et al.*

certainty under a regulatory model that gets reset every three years. The nine-year, five-month duration of the Company's proposed ESP will provide a level of certainty about the future that none of these stakeholders have enjoyed since deregulation began more than ten years ago.

Duke Energy Ohio's proposal is a straightforward structure. Rider RE and Rider AER-R are the only generation riders relevant to competitive offers. One transmission rider, Rider RTO, would be included in the price-to-compare as well. Although it is not a generation rider, it is a charge that is avoidable for switching customers. Thus, customers need only consider these riders for purposes of determining whether a CRES provider's offer is beneficial.

Finally, <u>all</u> retail customers, including those who are aggregated, benefit from the energy credit and participation in Duke Energy Ohio's Rider PSM. Accordingly, customers need not weigh whether exercising their right to choose generation suppliers will deprive them of receiving a credit. Furthermore, because Duke Energy Ohio will be the capacity provider for its entire footprint, all customers, including any those whose load is aggregated, will pay the Company's price for capacity and will, therefore, share in the net profits from energy and ancillary sales from the Legacy Generation Assets. As the Company's proposed economic development program includes the dedication of a portion of those same net profits toward economic development, those municipalities whose residents have aggregated are also eligible to receive the benefits of qualifying economic development projects.

## V. BETTER IN THE AGGREGATE TEST

**Q. IS THE COMPANY'S PROPOSED ESP BETTER, IN THE AGGREGATE,THAN EXPECTED RESULTS THAT WOULD OTHERWISE APPLY UNDER R.C. 4928.142, IN RESPECT OF PRICING?**

A. Yes. Attachment WDW-2 provides a summary of the projected generation rates customers can expect to pay under the Company's proposed ESP. I have also included the projected rates that "would otherwise apply under Section 4928.142 of the Revised Code." For ease of reference, the latter projected rates are referred to as the MRO rates. Duke Energy Ohio witness Rose includes a summary of the expected retail market prices for energy and for an 'all-in' product that would include energy and capacity. Using these price forecasts and the Company's forecasts for the net capacity rate (*i.e.*, Rider RC + Rider PSM), it is possible to estimate the overall generation price expected in the proposed ESP.

Multiplying the proposed ESP prices and the expected MRO prices by retail sales provides an estimate of the total value of either plan. As is shown on Attachment WDW-2, the net present value of the Company's proposed ESP is approximately $927 million greater than the total value of the alternative MRO using the same weighted-average cost of capital that was used in the calculation of the revenue requirement for Rider RC.

**Q. WHAT MEANING SHOUD THE COMMISSION TAKE FROM THIS COMPARISON?**

A. First, and foremost, the figures contribute significantly to the conclusion that the Company's proposed ESP is better in the aggregate than the results that could be expected under an MRO. Clearly, the Ohio General Assembly contemplated that the ESP versus MRO comparison was more than just economic but the fact that the Company's proposed ESP is almost $1 billion better than the MRO just on economic value is significant. As described by other Company witnesses, including Keith Trent and Julie Janson, Duke Energy Ohio believes the proposed ESP offers numerous other benefits that are less quantifiable. Combining the nearly $1 billion in economic value with the numerous other benefits of the ESP over the MRO absolutely satisfies the obligation under R.C. 4928.143(C)(1).

## VI. CONCLUSION

**Q. WERE ATTACHMENTS WDW-1 AND WDW-2 PREPARED UNDER YOUR DIRECTION?**

A. Yes.

**Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

Duke Energy Ohio
Revenue Requirement for Capacity Dedication
12 Months Ending 12/31/2010 (actuals)

Schedule A

| Line No. | Description | Reference | Amount |
|---|---|---|---|
| 1 | Production Rate Base | Schedule B-1 | $1,710,924,208 |
| 2 | Return on Rate Base | Schedule D | 7.88% |
| 3 | Return on Rate Base | *Calculated* | $134,820,828 |
| 4 | Operation & Maintenance Expense | Schedule C-2 | $274,690,153 |
| 5 | *Depreciation Expense* | *Schedule C-3* | $83,804,191 |
| 6 | Taxes Other Than Income Taxes | Schedule C-3 | $23,649,423 |
| 7 | Income Tax & Commercial Activities Tax (@0.26% of revenue) | Schedule C-4 | $49,374,541 |
| 8 | Annual Fixed Cost for Production | *Calculated* | $566,339,136 |
| 9 | Less: Credit for Customer Share of Generation Profits | Schedule E | ($144,295,425) |
| 10 | Net Amount to be Recovered in Retail Capacity Rider | *Calculated* | $422,043,711 |

Duke Energy Ohio
Rate Base Calculation (As of December 31, 2010)

Schedule B-1

| Line No. | Rate Base Component | Supporting Schedule | Allocated to Legacy Generation |
|---|---|---|---|
| | Plant in Service | | |
| 1 | Steam Production Plant | B-2 | $3,051,344,587 |
| 2 | Other Production Plant | B-2 | 21,943,247 |
| 3 | Total Production Plant | *calculated* | 3,073,287,834 |
| 4 | Transmission | B-2 | 23,043,118 |
| 5 | Distribution | B-2 | - |
| 6 | Intangible Plant | B-2.1 | - |
| 7 | General | B-2.1 | 32,447,023 |
| 8 | Common | B-2.1 | 99,262,688 |
| 9 | Total Plant In Service | *calculated* | $3,228,040,663 |
| | Reserve for Accumulated Depreciation | | |
| 10 | Steam Production Plant | B-2 | ($1,082,527,498) |
| 11 | Other Production Plant | B-2 | (26,258,999) |
| 12 | Total Production Plant | B-2 | (1,108,786,497) |
| 13 | Transmission | B-2 | (9,517,588) |
| 14 | Distribution | B-2 | - |
| 15 | Intangible Plant | | - |
| 16 | General | B-2 | (1,979,874) |
| 17 | Common | B-2 | (43,661,678) |
| 18 | Total Reserve for Accumulated Depreciation | *calculated* | ($1,163,945,637) |
| 19 | *Net Plant In Service (Line 7 + Line 14)* | *calculated* | $2,064,095,026 |
| 20 | Construction Work In Progress (production plant) | B-2 | $0 |
| 21 | Cash Working Capital Allowance | B-3 | $34,336,269 |
| 22 | Other Working Capital Allowance | B-3 | $158,871,180 |
| 23 | Other Items: | | |
| 24 | Deferred Income Taxes | B-4 | ($544,929,835) |
| 25 | Investment Tax Credits | B-4 | ($1,448,432) |
| 26 | Other Rate Base Adjustments | | $0 |
| 27 | Rate Base (Line 15 through Line 24) | *calculated* | $ 1,710,924,208 |

Duke Energy Ohio
Plant in Service

Schedule B-2

| Line No. | Account Title | Form 1 Reference | Total Company | Adjustments DEBA | Adjustments Purch Accts | Adjusted Total Company | Percent Allocated to Production | | Production Plant Allocated to SSO Service |
|---|---|---|---|---|---|---|---|---|---|
| | Gross Plant | | | | | | | | |
| 1 | Electric Production - Steam | p. 205(g)(16) | $3,330,170,587 | $0 | ($278,826,000) | $3,051,344,587 | 100.00% | | $3,051,344,587 |
| 2 | Electric Production - Other | p. 205(g)(45) | 1,717,309,032 | (1,695,365,785) | - | 21,943,247 | 100.00% | | 21,943,247 |
| 3 | Electric Transmission Plant | p. 207(g)(58) | 671,111,058 | (74,141,428) | - | 596,969,630 | 3.86% | (d) | 23,042,118 |
| 4 | Electric Distribution Plant | p. 207(g)(75) | 1,844,361,344 | - | - | 1,844,361,344 | 0.00% | | - |
| 5 | Miscellaneous Intangible Plant | p. 204(g)(5) | 76,062,040 | - | - | 76,062,040 | 0.00% | | - |
| 6 | General Plant | p. 207(g)(99) | 104,175,568 | (21,381,428) | - | 82,794,140 | 39.19% | | 32,447,023 |
| 7 | Common Plant (Elec portion) | p. 356.2 | 253,285,756 | - | - | 253,285,756 | 39.19% | | 99,262,588 |
| 8 | Total Gross Plant | | $7,996,475,385 | ($1,790,888,641) | ($278,826,000) | $5,926,760,744 | | | $3,228,040,669 |
| | Accumulated Depreciation | | | | | | | | |
| 9 | Electric Production - Steam | p. 219(c)(20) | ($1,188,561,498) | $0 | $106,034,000 | ($1,082,527,498) | 100.00% | | ($1,082,527,498) |
| 10 | Electric Production - Other | p. 219(c)(24) | (466,698,116) | 440,439,117 | - | (26,258,999) | 100.00% | | (26,258,999) |
| 11 | Electric Transmission Plant | p. 219(c)(25) | (243,399,552) | 30,046,550 | - | (213,353,002) | 4.46% | (d) | (9,517,588) |
| 12 | Electric Distribution Plant | p. 219(c)(26) | (625,814,226) | - | - | (625,814,226) | 0.00% | | - |
| 13 | Miscellaneous Intangible Plant | | | - | - | - | 0.00% | | - |
| 14 | General Plant | p. 219(c)(28) | (10,627,310) | 5,575,323 | - | (5,051,987) | 39.19% | | (1,979,874) |
| 15 | Common Plant (Elec portion) | p. 356.2 | (111,410,252) | - | - | (111,410,252) | 39.19% | | (43,661,678) |
| 16 | Total Accumulated Depreciation | | ($2,646,510,954) | $476,060,990 | $106,034,000 | ($2,064,415,964) | | | ($1,163,945,637) |
| | Construction Work in Progress | (a) | | | | | | | |
| 17 | Electric Production - Steam | (b) | $58,745,649 | $0 | $0 | $58,745,649 | 100.00% | | $58,745,649 |
| 18 | Electric Production - Other | (b) | 629,201 | (629,201) | - | - | 100.00% | | - |
| 19 | Electric Transmission Plant | (b) | - | - | - | - | 0.00% | | - |
| 20 | Electric Distribution Plant | (b) | 48,671,842 | - | - | 48,671,842 | 0.00% | | - |
| 21 | Miscellaneous Intangible Plant | (b) | - | - | - | - | 0.00% | | - |
| 22 | General Plant | (b) | 13,334,528 | - | - | 13,334,528 | 39.19% | | 5,225,802 |
| 23 | Common Plant | (c) | - | - | - | - | 39.19% | | - |
| 24 | Total Construction Work in Progress | p. 200(c)(11) | $121,381,220 | ($629,201) | $0 | $120,752,019 | | | $63,971,451 |

Notes: (a) Excludes AFUDC and capitalized interest.
(b) Internal Accounting Records.
(c) Common Plant CWIP included in line 7
(d) Step up transformers.

Duke Energy Ohio
Working Capital

Schedule B-3

| Line No. | Account Title | | Source | Amount |
|---|---|---|---|---|
| 1 | Cash Element of Working Capital | Based on 1/8 Oper. & Maint. Expense less purchased gas costs or fuel and purchased power expenses. | Sch C-2.1 ÷ 8 | $34,336,269 |
| | Other Working Capital: | | | |
| 2 | Fuel Stock | | Sch B-3.1 | $82,733,128 |
| | Emission Allowance Inventory | | | |
| 3 | $SO_2$ Emission Allowances | | Sch B-3.1 | $23,545,397 |
| 4 | $NO_x$ Emission Allowances | | Sch B-3.1 | $1,101,380 |
| 5 | Materials and Supplies | | Sch B-3.1 | $36,873,430 |
| 6 | Prepayments | | Sch B-3.1 | $14,617,846 |
| 7 | Total Other Working Capital | | *Sum* | $158,871,180 |
| 8 | Total Working Capital | | *Sum* | $193,207,449 |

Duke Energy Ohio
Other Working Capital

Schedule B-2.1

| Line No. | FERC Acct | Account Title | Source | Total Company [a] | Adjustments: Other/Non-Native | Adjustments: Purch Accts | Adjusted Total Company | Percent Allocated to Production | Production Plant Allocated to SSO Service |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 151 | Fuel Stock | p. 227.1.b & 227.1.c | $84,365,447 | (11,219) | (1,621,100) | $82,733,128 | 100.00% | $82,733,128 |
| 2 | 154 | Materials and Supplies (Production) | p. 227.3.b & 227.3.c | 46,594,305 | (9,720,875) | - | 36,873,430 | 100.00% | $36,873,430 |
| 3 | 165 | Prepayments | p. 111.57.c | 15,120,900 | (503,054) | - | 14,617,846 | 100.00% | $14,617,846 |
| 4 | 158 | $SO_2$ Emission Allowances | p. 228a.b.m.1 & 228a.l.m.29 | 148,146,419 | (124,601,022) | - | 23,545,397 | 100.00% | $23,545,397 |
| 5 | 158 | $NO_x$ Emission Allowances | p. 228b.b.m.1 & 228b.l.m.29 | 3,553,093 | (2,451,713) | $0 | $1,101,380 | 100.00% | $1,101,380 |

Notes: [a] Average of beginning and ending balance for 2010.

Duke Energy Ohio
Accumulated Deferred Income Taxes and Investment Tax Credits

Schedule B-4

| Line No. | Account Title | Form 1 Source | Total Company | Legacy Generation | Other Electric | Gas |
|---|---|---|---|---|---|---|
| 1 | Account 190 | p. 234 | $150,680,487 | $57,180,700 | $44,281,910 | $49,217,877 |
| 2 | Account 281 | p. 273 | (15,661,825) | (15,661,825) | - | - |
| 3 | Account 282 | p. 275 | ($1,277,200,963) | ($463,794,104) | ($633,529,624) | ($179,877,235) |
| 4 | Account 283 | p. 277 | (244,845,319) | (122,654,606) | (80,051,376) | (47,033,917) |
| 5 | Total Deferred Tax Adjustment | Sum | ($1,387,027,620) | ($544,929,835) | ($669,299,090) | ($177,693,275) |
| 6 | Investment Tax Credit (Account 255) | p. 267 | $3,695,922 | $1,448,432 | $2,247,490 | 3,125,491 |

Note: The data above was taken from Duke Energy Ohio's internal accounting records. The information does not tie to the FERC Form 1 due to differences in the manner in which ADITs are aggregate internally and reported for FERC Form 1. All detail for the ADITs are provided in Schedule B-4.1.

Duke Energy Ohio
Accumulated Deferred Income Taxes and Investment Tax Credits

Schedule B-4.1

| Line No. | Account Title | Total Company | Legacy Generation | Other Electric | Gas |
|---|---|---|---|---|---|
| | Account 190 (Detailed Accounts) | | | | |
| 1 | FERC - FIT Adj Offset to Regulatory Asset (254100) | ($2,117,500) | $0 | ($1,481,756) | ($635,744) |
| 2 | KY 190002 Adjustment to Deferreds | (34,714) | - | (34,714) | - |
| 3 | Bad Debts - Tax over Book | 866,053 | - | 443,094 | 422,959 |
| 4 | Uncollectible Provision PIP ADJ | (280,737) | - | - | (280,737) |
| 5 | Offsite Gas Storage Costs | 2,943,146 | - | - | 2,943,146 |
| 6 | Asset Retirement Obligation | 7,213,626 | 1,554,043 | 190,087 | 5,469,496 |
| 7 | Property Tax - Propane Inventory | 471,021 | - | - | 471,021 |
| 8 | Leased Meters - Elec & Gas | (6,379,598) | - | (7,019,553) | 639,955 |
| 9 | Meters & Transformers | (832,743) | - | (832,743) | - |
| 10 | Lease Meters-Current | 73,306 | - | 45,354 | 27,952 |
| 11 | Mark to Market - ST | (9,792,640) | (12,692,999) | 2,900,359 | - |
| 12 | Mark to Market - LT | 27,839,152 | 542,255 | 27,296,897 | - |
| 13 | Unamortized Debt Premium | 781,097 | 1,123,308 | (249,940) | (92,271) |
| 14 | Unamortized Debt Discount | (2,309,335) | (2,511,472) | 1,555,552 | (1,353,415) |
| 15 | Cash Flow Hedge - Reg Asset/Liab | (857,706) | - | (857,706) | - |
| 16 | Save-A-Watt Regulated Deferred Liability | 4,018,321 | - | 4,018,321 | - |
| 17 | Accrued Vacation | 4,565,627 | 1,681,646 | 1,898,026 | 985,955 |
| 18 | Property Tax Reserves | 5,391,011 | 13,394,664 | (17,072,530) | 9,068,877 |
| 19 | Severance Accrual ST | 11,850 | 9,660 | 1,596 | 594 |
| 20 | MGP Sites | 17,349,358 | - | (217,583) | 17,566,941 |
| 21 | Employee Benefits | (2,513,947) | (987,002) | (991,327) | (535,618) |
| 22 | Gas Supplier Refunds | 96,611 | - | - | 96,611 |
| 23 | Natural Gas In Transit | 111,449 | - | - | 111,449 |
| 24 | Unbilled Revenue - Fuel | 6,961,868 | - | - | 6,961,868 |
| 25 | Demand Side Management (DSM) Defer | 746,055 | - | 746,055 | - |
| 26 | Emission Allowance Expense | 31,598,644 | 31,598,644 | - | - |
| 27 | Retirement Plan Expense - Underfunded | 113,402,304 | 49,677,533 | 44,329,338 | 19,395,433 |
| 28 | Non-qualified Pension - Accrual | 2,158,967 | 846,842 | 906,013 | 406,112 |
| 29 | Retirement Plan Funding - Underfunded | (68,875,504) | (25,927,633) | (27,546,000) | (13,408,891) |
| 30 | Non-qualified Pension - Payment | (254,008) | (92,524) | (161,484) | - |
| 31 | Environmental Reserve | (256) | - | (256) | - |
| 32 | Joint Owner Pension Receivable | (3,456,410) | (3,453,421) | (2,989) | - |
| 33 | FAS 87 Qual Plan OCI | (16,348,209) | (16,348,209) | - | - |
| 34 | Accrued Pension Admin Fees | 1,033,857 | 1,033,787 | 70 | - |
| 35 | Accrual NQ Pension ST | 260,615 | 74,797 | 130,258 | 55,560 |
| 36 | FAS 87 Non Qual Plan OCI | (73,616) | (73,616) | - | - |
| 37 | FAS 106 OPEB OCI | 4,539,776 | 4,539,776 | - | - |
| 38 | Annual Incentive Plan Comp | 670,473 | 284,019 | 282,376 | 104,078 |
| 39 | Payable 401 (K) Match | 59,482 | 19,986 | 27,707 | 11,839 |
| 40 | SIT - Known Reserves - Cur Asset | 61,541 | 76,502 | (14,961) | - |
| 41 | Tax Interest Accrual - Cur Liab | (138,054) | - | (138,054) | - |
| 42 | Tax Int Accrual - Non-cur Liab | 2,448,850 | - | 2,448,850 | - |
| 43 | OPEB Expense Accrual | 19,780,082 | 4,886,154 | 14,057,890 | 796,038 |
| 44 | OPEB Funding Payment | (2,575,906) | (818,361) | (1,391,321) | (366,224) |
| 45 | FAS 112 Medical Expenses Accrual | 1,941,272 | 741,241 | 795,698 | 404,330 |
| 46 | FAS 112 Medical Funding Payment | (314,470) | (50,319) | (234,349) | (29,802) |
| 47 | OPEB Admin Fees | (3,415,297) | (3,414,332) | (965) | - |
| 48 | Accrual OPEB ST | 32,894 | (60,865) | 77,121 | 15,718 |
| 49 | Accrual Post Retirement ST | (77,182) | (55,463) | (9,496) | (12,224) |

Duke Energy Ohio
Accumulated Deferred Income Taxes and Investment Tax Credits

Schedule B-4.1

| Line No. | Account Title | Total Company | Legacy Generation | Other Electric | Gas |
|---|---|---|---|---|---|
| 50 | OCI - FAS 106 Actuarial Gain/Loss | (4,539,776) | (4,539,776) | - | - |
| 51 | OCI - Actuarial GL Qual | 16,348,299 | 16,348,299 | - | - |
| 52 | OCI - Actuarial GL NQ | 73,616 | 73,616 | - | - |
| 53 | Federal Benefit of State for 190 CY | 58,050 | - | 58,050 | - |
| 54 | Federal Benefit of State for 190 PY | 620,111 | - | 620,111 | - |
| 55 | Federal Benefit of State on 190 Gain Contingency PY | 1,036,888 | - | 1,036,888 | - |
| 56 | Miscellaneous | (1,715,046) | - | (1,714,791) | (255) |
| 57 | Total Account 190 | $150,680,487 | $57,180,700 | $44,281,910 | $49,217,877 |
| | Account 281 (Detailed Accounts) | | | | |
| 58 | Pollution Control | ($15,661,825) | ($15,661,825) | $0 | $0 |
| | Account 282 (Detailed Accounts) | | | | |
| 59 | Other Non-Current After-Tax DTL for PP&E | ($6,913,547) | $0 | ($6,913,547) | $0 |
| 60 | Other Non-Current AT ST DTL for PP&E | (5,348) | - | (5,348) | - |
| 61 | FERC - FIT Plant Adj (Util - 411) | 9,420,173 | - | 9,420,173 | - |
| 62 | FERC - FIT Plant Adj (Util - 410) | (1,198,171,621) | (389,773,184) | (675,425,443) | (132,972,994) |
| 63 | FERC - FIT Plant Adj (Util - 411) | (3,152,122) | (3,424,067) | 271,945 | - |
| 64 | FERC - SIT Plant Adj (Util - 410) | (12,864,043) | (17,062,585) | 9,570,270 | (5,371,728) |
| 65 | FERC - SIT Plant Adj (Util 411) | 4,250,249 | (1,181,782) | 341,545 | 5,090,486 |
| 66 | FERC - FIT Adj Offset to Regulatory Liability (182320) | 13,348,634 | (3,012,041) | 16,728,483 | (367,808) |
| 67 | KY 282101 Adjustment to Deferreds | (1,683,642) | - | (1,683,642) | - |
| 68 | AFUDC Interest | (449,897) | - | (472,216) | 22,319 |
| 69 | Repairs Allowed on Post ADR Prop | (746,844) | (270,620) | (252,561) | (223,663) |
| 70 | Book Depreciation/Amortization | 278,666,136 | 114,084,544 | 129,438,931 | 35,142,661 |
| 71 | Book Gain/Loss on Property | (89,829) | - | (89,829) | - |
| 72 | Contributions In Aid (CIACs) | 3,149,116 | 486,708 | 812,158 | 1,850,250 |
| 73 | Cost of Removal | (2,229,679) | 63,107 | (1,283,042) | (1,009,744) |
| 74 | Tax Interest Capitalized | 7,706,653 | 5,764,518 | 1,204,412 | 737,723 |
| 75 | Tax Depreciation/Amortization | (383,337,124) | (196,672,243) | (121,070,233) | (65,594,648) |
| 76 | Tax Gains/Losses | (11,078,329) | 6,564 | 153,505 | (11,238,398) |
| 77 | Casualty Loss | (3,525,213) | (3,525,213) | - | - |
| 78 | Section 174 R&E Deduction | (956,942) | (590,008) | (366,934) | - |
| 79 | Repairs 481(a) (Pursuant to 3115) | (27,352,656) | (27,352,656) | - | - |
| 80 | FAS 34 | (4,864,002) | (4,802,252) | (65,112) | 3,362 |
| 81 | Book Depr On Trans Equip to ADR | 221,484 | (305) | 190,683 | 31,106 |
| 82 | Excess Salvage | 777,530 | - | 38,692 | 738,838 |
| 83 | 263A ADJUSTMENT | (5,107,145) | (571,906) | (4,535,239) | - |
| 84 | Loss on ACRS | (11,141,280) | (307,491) | (6,799,681) | (4,034,108) |
| 85 | Non-Cash Overhead Basis Adj | 36,455,019 | 2,789,838 | 34,198,830 | (533,649) |
| 86 | Equipment Repairs - Annual Adj | (57,479,136) | (55,100,136) | (2,379,000) | - |
| 87 | 481(a) Fixed Asset Retirement | 265,265 | 265,265 | - | - |
| 88 | Impairment of Plant Assets | 57,497,207 | 57,497,207 | - | - |
| 89 | T & D Repairs 481(a) (pursuant to 3115) | (12,340,414) | - | (12,340,414) | - |
| 90 | T & D Repairs - Annual Adj. | 716,599 | - | 716,599 | - |
| 91 | Self Developed Software | (7,212,407) | (2,504,984) | (3,137,914) | (1,569,509) |
| 92 | Asset Retirement Costs - ARO | (628,200) | 17,231 | 93,024 | (738,455) |
| 93 | KY - Bonus Depreciation Adj | 475,392 | 172,964 | 140,399 | 162,029 |

Duke Energy Ohio
*Accumulated Deferred Income Taxes and Investment Tax Credits*

Schedule B-4.1

| Line No. | Account Title | Total Company | Legacy Generation | Other Electric | Gas |
|---|---|---|---|---|---|
| 94 | OH - Bonus Depreciation Adj | 38,622 | 19,737 | 3,901 | 14,984 |
| 95 | OH - Franchise Tax Adj | (64,166) | (14,864) | (33,013) | (16,289) |
| 96 | Purchase Accounting Adjustment | 61,204,550 | 61,204,550 | | |
| 97 | Total Account 282 | ($1,277,200,957) | ($463,794,104) | ($633,529,618) | ($179,877,235) |
| | Account 283 (Detailed Accounts) | | | | |
| 98 | Other Non-Current After-Tax DTL | (6,740,341) | $0 | ($6,740,341) | $0 |
| 99 | KY 283101 Adjustment to Deferreds | (17,357) | - | (17,357) | - |
| 100 | Noncurrent Bad Debt Provision | 1,275,319 | - | (1,074,113) | 2,349,432 |
| 101 | Reverse Book Partnership Earnings | 347,959 | - | 347,959 | - |
| 102 | POST IN SERVICE - CARRYING COSTS | (4,962,909) | - | - | (4,962,909) |
| 103 | Loss on Reacquired Debt-Amort | (2,174,199) | - | (1,390,719) | (783,480) |
| 104 | Merger Costs | 195,247 | 72,211 | 57,718 | 65,318 |
| 105 | RTC Amortization | (1,039,005) | - | (1,039,005) | - |
| 106 | RSP Costs Capitalization | (42,443,388) | (41,890,132) | (553,256) | - |
| 107 | Inventory & Contract Write-up | (1,928,259) | (1,928,259) | - | - |
| 108 | Reg Asset/Liab Def Revenue | (7,076,041) | (7,076,041) | - | - |
| 109 | Reg Asset - Accr Pension FAS158 - FAS87Qual | (27,923,666) | - | (21,711,853) | (6,211,813) |
| 110 | Reg Asset Smart Grid Gas Furnace | (2,255,870) | - | (2,255,870) | - |
| 111 | Reg Asset Smart Grid Dfd Other O&M | (4,314,445) | - | (3,164,681) | (1,149,764) |
| 112 | Reg Asset Smart Grid PISCC | (1,932,480) | - | (1,613,510) | (318,970) |
| 113 | Reg Asset Smart Grid Deferred Depr. | (1,474,058) | - | (1,269,442) | (204,616) |
| 114 | Reg Liab RSLI & Other Misc Dfd Costs | 33,404 | - | 33,404 | - |
| 115 | Reg Asset Hurricane Ike Storm Damage | (5,667,325) | - | (5,667,325) | - |
| 116 | Reg Asset - MGP Costs | (21,216,275) | - | - | (21,216,275) |
| 117 | Reg Asset - Elec Rate Case Expense | (159,326) | - | (230,160) | 70,834 |
| 118 | Reg Asset-Pension Post Retirement PAA-FAS87Qual anc | (29,857,547) | - | (18,829,475) | (11,028,072) |
| 119 | Reg Asset - DEO Econ Dev | (354,209) | - | (354,209) | - |
| 120 | Vacation Carryover - Reg Asset | (1,977,629) | - | (1,386,275) | (591,354) |
| 121 | Rate Case - Deferred Costs | (183,455) | - | (183,455) | - |
| 122 | Deferred Fuel Cost Purch Gas Adjustment | 1,680,031 | - | - | 1,680,031 |
| 123 | Deferred Pipeline Installation Costs | (425,568) | - | (425,568) | - |
| 124 | Emission Allowance Trading | (71,827,955) | (71,827,955) | - | - |
| 125 | Retirement Plan Expense - Overfunded | 6,196,136 | - | 6,196,136 | - |
| 126 | Retirement Plan Funding - Overfunded | (13,950,396) | - | (13,950,396) | - |
| 127 | Miscellaneous Current Taxable Inc. Adj - DTL | (2,959,479) | - | (2,959,479) | - |
| 128 | Sec 481 Adj - State Inc Tax | (886) | (886) | - | - |
| 129 | Tax Interest Accrual - Cur Asset | (1,210,526) | - | (1,210,526) | - |
| 130 | Tax Int Accrual - Non-cur Asset | (497,277) | - | (497,277) | - |
| 131 | ARO Regulatory Asset | (3,544) | (3,544) | (162,301) | (4,732,279) |
| 132 | Total Account 283 | ($244,845,319) | ($122,654,606) | ($80,051,376) | ($47,033,917) |

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Summary of Legacy Generation-Related O&M expenses

Schedule C-2

| Line No | FERC Account | Account Description (Form 1, pages 320-323) | Total Per Books | Adjustments: OGMA | Adjustments: Purch Accts | Adjustments: Other | Adjusted Total | % Allocable To Prod Demand | Not Allocated To Prod Demand | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Steam Power Generation | | | | | | | | |
| | | Operation | | | | | | | | |
| 1 | [redacted] | | | | | | | | | |
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CONFIDENTIAL PROPRIETARY TRADE SECRET



Duke Energy Ohio
Summary of Legacy Generation-Related O&M expenses

Schedule G-2

| Line No | FERC Account | Accounts Description (Form 1, pages 320-323) | Total Per Books | Adjustments: OVEA | Adjustments: Purch Accts | Adjustments: Other | Adjusted Total | % Allocable To Prod Demand | Net Allocated To Prod Demand | Note |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Administrative and General expenses | | | | | | | | |
| | | Operation | | | | | | | | |
| 1 | [redacted] | | | | | | | | | |
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| 15 | | | | | | | | | | |

Duke Energy Ohio
Depreciation Expense & Property Taxes

Schedule C-3

| Line No. | Account Title | Source | Total Company | Adjustments DENA | Adjustments Purch Acctg | Adjusted Total | Percent Allocated to Production | Amount for Legacy Gen |
|---|---|---|---|---|---|---|---|---|
| | Depreciation Expense | | | | | | | |
| 1 | Intangible Plant | p. 336.1f | $17,504,993 | $0 | ($7,755,000) | $9,749,993 | 39.2% | $3,821,022 |
| 2 | Steam Production Plant | p. 336.2f | 73,725,960 | - | - | 73,725,960 | 100.0% | 73,725,960 |
| 3 | Other Production Plant | p. 336.4f | 58,360,702 | (58,166,842) | - | 193,860 | 100.0% | 193,860 |
| 4 | Transmission Plant | p. 336.7f | 11,107,812 | - | - | 11,107,812 | 0.0% | - |
| 5 | Distribution Plant | p. 336.8f | 42,678,072 | - | - | 42,678,072 | 0.0% | - |
| 6 | General Plant | p. 336.10f | 2,923,288 | - | - | 2,923,288 | 39.2% | 1,145,637 |
| 7 | Common Plant - Electric | p. 336.11f | 14,812,386 | - | - | 14,812,386 | 33.2% | 4,917,712 |
| 8 | Total Depreciation Expense | | $221,113,213 | ($58,166,842) | ($7,755,000) | $155,191,371 | | $83,804,191 |
| | Property Tax | | | | | | | |
| 9 | Intangible Plant | | $0 | $0 | $0 | $0 | 39.2% | $0 |
| 10 | Steam Production Plant | | 15,029,700 | - | - | 15,029,700 | 100.0% | 15,029,700 |
| 11 | Other Production | | 3,714,939 | (3,714,939) | - | - | 100.0% | - |
| 12 | Transmission Plant | Notes to p. 262.263 | 17,322,248 | - | - | 17,322,248 | 0.0% | - |
| 13 | Distribution Plant | Total FERC elec less T & Gen | 55,210,089 | - | - | 55,210,089 | 0.0% | - |
| 14 | General & Common (Electric) | Common alloc to Elec | 6,307,819 | - | - | 6,307,819 | 39.2% | 2,472,034 |
| 15 | Total Property Taxes | | $97,584,795 | ($3,714,939) | $0 | $93,869,856 | | $17,501,734 |
| 16 | Payroll Taxes | p. 263.4.5.12i | 12,810,088 | (678,604) | - | 12,131,484 | 44.5% | 5,400,771 |
| 17 | Franchise Tax | | 1,642,804 | - | - | 1,642,804 | 44.5% | 731,354 |
| 18 | Commercial Activities Tax [a] | | 4,568,022 | - | - | 4,568,022 | 0.0% | - |
| 19 | Highway Use Tax | | 34,961 | - | - | 34,961 | 44.5% | 15,564 |
| 20 | Total Taxes Other Than Income | | $116,640,670 | ($4,393,543) | $0 | $112,247,127 | | $23,649,423 |

Note: [a] Commercial Activities Tax of 0.26% included in Schedule A revenue requirement calculation.

**Duke Energy Ohio** **Schedule C-4**
**Calculation of Income Tax Factors**

| Line No | Description | Amount |
|---|---|---|
| 1 | Income before Federal Income Tax | 100.00% |
| 2 | Gross Domestic Production Tax Credit | 9.00% |
| 3 | Income After Gross Domestic Tax Credit | 91.00% |
| 4 | Federal Income Tax 35.00% | 31.85% |
| 5 | Gross Revenue Conversion Factor (1/(1-0.3442)) | 1.4674 |

Duke Energy Ohio
Capitalization and Cost of Capital as of December 31, 2010

Schedule D

| Line No. | Account Title | Total Company (a) | Adjustments: DENA (b) | Adjustments: Purch Accts (c) | Adjusted Total Company (d) | Ratio (e) | Cost Rate [f] (f) | After-Tax WACC (g) | GRCF [h] (h) | Pre-Tax WACC (i) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Common Equity | $5,463,938,777 | ($1,077,160,243) | ($1,180,779,435) | $3,205,999,099 | 55.8% | 10.75% | 6.00% | 1.4674 | 8.80% |
| 2 | Preferred Equity | - | - | - | - | - | - | - | - | - |
| 3 | Long-Term Debt | 2,534,482,320 | - | 2,330,168 | 2,536,812,488 | 44.2% | 4.26% | 1.88% | 1.0026 | 1.88% |
| 4 | Total Capitalization | $7,998,421,097 | ($1,077,160,243) | ($1,178,449,267) | $5,742,811,587 | 100.0% | | 7.88% | | 10.68% |

Notes: [a] Per Books Capital for DE-Ohio Consolidated. (As reported in the Company's Compliance Filing for Significantly Excessive Earnings Test, Case No. 11-2934-EL-UNC.)
[b] Based on internal account information.
[c] Based on internal account information.
[d] Sum of Columns (a), (b), and (c).
[e] As percent of total capitalization.
[f] Return on Equity rate as proposed by Company. Interest on long-term debt is actual interest expense from Form 1, page 257.33.I, divided by LTD balance above.
[g] Column (e) * (Column (f)).
[h] Gross Revenue Conversion Factor (GRCF) calculated on Schedule C-4.
[i] Column (g) * (Column (h)).

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Calculation of Credit for Profit Sharing Mechanism

Schedule E

| Line No | Description | Amount |
| --- | --- | --- |
| [redacted] | | |

Attachment WDW-1


Duke Energy Ohio
Allocation of Capacity Costs for Rate Design

Schedule F

| Line No | Description | 12 CP (a) | Percent of Total 12 CP Demand (b) | Allocation of Fixed Gen Rev Req (c) | Allocation of PSM Credit (d) | Net Capacity Rev Req (e) | |
|---|---|---|---|---|---|---|---|
| | *Average of 12 CP Demand by Rate Schedule:* | | | | | | |
| 1 | Residential (RS, TD, ORH) | 1,582,861 | 46.76% | $264,821,457 | ($67,472,866) | $197,348,591 | To Rate Design |
| 2 | Electric Space Heating (EH) | 13,736 | 0.41% | 2,297,979 | (585,493) | 1,712,486 | |
| 3 | Secondary Distribution - Small (DM) | 87,168 | 2.57% | 14,582,862 | (3,715,513) | 10,867,349 | |
| 4 | Unmetered Small Fixed Load (GSFL, ADPL) | 4,746 | 0.14% | 793,987 | (202,297) | 591,690 | |
| 5 | Secondary Distribution (DS) | 978,791 | 28.91% | 163,747,872 | (41,720,706) | 122,027,166 | |
| 6 | Primary Distribution (DP) | 311,768 | 9.21% | 52,157,556 | (13,289,028) | 38,868,528 | |
| 7 | Transmission Voltage (TS) | 390,191 | 11.53% | 65,277,415 | (16,631,788) | 48,645,627 | |
| 8 | Lighting | 15,900 | 0.47% | 2,660,007 | (677,733) | 1,982,274 | |
| 9 | Total | 3,385,251 | 100.00% | $566,339,136 | ($144,295,425) | $422,043,710 | |

Notes: [a] Average of 12 Coincident Monthly Peaks based on load research data for 2010.

Duke Energy Ohio
Allocation Factors

Allocation Factors

| Line No. | Category | Form 1 Reference | Per Books | Adjustments DENA | Adjustments Purch Acctg | Adjusted Total Company | Ratio |
|---|---|---|---|---|---|---|---|
| | W&S Allocator for Electric | | | | | | |
| 1 | Production | 354.20.b | $57,676,930 | 10,780,226 | | $46,896,704 | 44.5% |
| 2 | Transmission | 354.21.b | 3,321,634 | | | | |
| 3 | Distribution | 354.23.b | 23,830,724 | | | | |
| 4 | Other [a] | 354.24,25,26.b | 20,512,455 | | | | |
| 5 | Total | | $105,341,743 | | | | |

| Line No. | Category | Form 1 Reference | Per Books | % Electric | W&S Allocator | W&S for Common |
|---|---|---|---|---|---|---|
| | W&S Allocator for Common | | | | | |
| 6 | Electric | 200.8.c | $7,996,676,383 | 84.7% | 44.5% | 37.7% |
| 7 | Gas | 201.8.d | 1,442,435,032 | | | |
| 8 | Total | | $9,439,111,415 | | | |
| 9 | Electric G, T, D Gross Plant | | $7,841,778,021 | | | |
| 10 | Legacy Generation (Gross Plant) | | $3,073,287,834 | | | |
| 11 | Legacy Gen GP as % if G, T, D Plant | | 39.19% | | | |
| 12 | Legacy Gen GP as % of G&E Plant | | 33.20% | | | |

Notes: [a] "Other" includes labor for Customer Accounts, Customer Service & Information, Customer Service & Informational, and Sales, all of which are allocated to distribution expenses.

# CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Revenue Requirement for Capacity Dedication
12 Months Ending 12/31



| Line No. | Description | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Production Rate Base | $1,710,924,208 | $1,812,539,468 | $1,867,177,315 | $1,992,884,930 | $2,172,178,886 | $2,273,773,857 | $2,281,811,416 | $2,332,618,257 | $2,323,273,786 | $2,292,406,444 |
| 2 | Return on Rate Base | 7.88% | 7.88% | 7.88% | 7.88% | 7.88% | 7.88% | 7.88% | 7.88% | 7.88% | 7.88% |
| 3 | Return on Rate Base | $134,820,828 | $142,828,110 | $147,133,565 | $157,058,072 | $171,167,696 | $179,175,380 | $179,806,740 | $183,810,319 | $183,073,974 | $180,641,628 |
| 4 | Operation & Maintenance Expense | $274,680,153 | $244,424,905 | $318,800,370 | $361,793,087 | $325,331,493 | $352,509,276 | $380,342,054 | $412,675,462 | $433,569,912 | $442,546,474 |
| 5 | Depreciation Expense | $85,804,191 | $83,327,959 | $80,746,817 | $80,734,064 | $84,987,271 | $88,506,785 | $90,661,942 | $95,625,170 | $99,087,192 | $101,424,883 |
| 6 | Taxes Other Than Income Taxes | $23,649,423 | $20,184,187 | $19,947,682 | $20,133,048 | $17,262,884 | $17,817,018 | $18,084,275 | $18,355,537 | $18,630,870 | $18,910,333 |
| 7 | Income Tax | $49,374,542 | $30,731,105 | $32,280,962 | $55,800,330 | $60,621,009 | $63,665,668 | $63,880,720 | $65,313,311 | $65,051,666 | $64,187,380 |
| 8 | Annual Fixed Cost for Production | $566,329,136 | [redacted] | | | | | | | | |
| 9 | Total Retail Sales (MWh) | | | | | | | | | | |
| 10 | Average cost of capacity before credits ($/MWh) | | | | | | | | | | |
| 11 | Estimated Credit for Customer Share of Generation Profits | | | | | | | | | | |
| 12 | Net Production Fixed Cost for Native Load | | | | | | | | | | |
| 13 | Projected Retail Energy Price (Rose Testimony, Exhibit F-8) | $58.14 | $63.84 | $69.43 | $75.81 | [redacted] | | | | | |
| [redacted] | | | | | | | | | | | |
| 15 | Projected Generation Price under MRO (Rose Testimony, Exhibit -FF) | $77.40 | $77.80 | $77.09 | $81.40 | [redacted] | | | | | |
| 18 | NPV of Revenue at Proposed Rates (discounted at WACC) ($million) | $14,413 | | | | | | | | | |
| 19 | NPV of Revenue at MRO Rates (discounted at WACC) ($million) | $15,339 | | | | | | | | | |
| 20 | Difference ($million) | ($927) | | | | | | | | | |

**Duke Energy Ohio**
**Projected Rate Base for Legacy Generation**
**12 Months Ending 12/31**

| Rate Base Components | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Plant In Service** | | | | | | | | | | |
| Steam Production Plant | $3,051,344,587 | $3,399,300,913 | $3,522,369,904 | $3,719,062,304 | $3,975,909,286 | $4,158,743,817 | $4,256,292,063 | $4,395,610,627 | $4,480,380,419 | $4,545,977,169 |
| Other Production Plant | $21,943,247 | | | | | | | | | |
| Total Production Plant | $3,073,287,834 | $3,399,300,913 | $3,522,369,904 | $3,719,062,304 | $3,975,909,286 | $4,158,743,817 | $4,256,292,063 | $4,395,610,627 | $4,480,380,419 | $4,545,977,169 |
| Transmission | $23,048,118 | | | | | | | | | |
| Distribution | $0 | | | | | | | | | |
| Intangible Plant | $0 | | | | | | | | | |
| General | $32,447,023 | | | | | | | | | |
| Common | $99,262,688 | | | | | | | | | |
| Total Plant In Service | $3,228,040,663 | $3,399,300,913 | $3,522,369,904 | $3,719,062,304 | $3,975,909,286 | $4,158,743,817 | $4,256,292,063 | $4,395,610,627 | $4,480,380,419 | $4,545,977,169 |
| **Reserve for Accumulated Depreciation** | | | | | | | | | | |
| Steam Production Plant | ($1,082,527,498) | (1,227,831,337) | (1,298,024,022) | (1,369,835,111) | (1,447,289,979) | (1,530,176,524) | (1,616,406,081) | (1,707,598,866) | (1,802,253,674) | (1,899,246,172) |
| Other Production Plant | ($26,258,999) | | | | | | | | | |
| Total Production Plant | ($1,108,786,497) | ($1,227,831,337) | ($1,298,024,022) | ($1,369,835,111) | ($1,447,289,979) | ($1,530,176,524) | ($1,616,406,081) | ($1,707,598,866) | ($1,802,253,674) | ($1,899,246,172) |
| Transmission | ($9,517,588) | | | | | | | | | |
| Distribution | $0 | | | | | | | | | |
| Intangible Plant | $0 | | | | | | | | | |
| General | ($1,979,874) | | | | | | | | | |
| Common | ($43,661,678) | | | | | | | | | |
| Total Reserve for Accumulated Depreciation | ($1,163,945,637) | ($1,227,831,337) | ($1,298,024,022) | ($1,369,835,111) | ($1,447,289,979) | ($1,530,176,524) | ($1,616,406,081) | ($1,707,598,866) | ($1,802,253,674) | ($1,899,246,172) |
| **Net Plant In Service** | $2,064,095,026 | $2,171,469,576 | $2,224,345,882 | $2,349,227,194 | $2,528,619,307 | $2,628,567,293 | $2,639,885,982 | $2,688,011,761 | $2,678,126,746 | $2,646,730,997 |
| Construction Work in Progress (production plant) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Cash Working Capital Allowance | $34,336,269 | $28,576,980 | $30,338,419 | $31,148,823 | $31,066,666 | $32,713,651 | $29,432,521 | $32,113,584 | $32,654,127 | $33,182,534 |
| Other Working Capital Allowance | $158,871,180 | $158,871,180 | $158,871,180 | $158,871,180 | $158,871,180 | $158,871,180 | $158,871,180 | $158,871,180 | $158,871,180 | $158,871,180 |
| Other Items: | | | | | | | | | | |
| Deferred Income Taxes | ($544,929,835) | ($544,929,835) | ($544,929,835) | ($544,929,835) | ($544,929,835) | ($544,929,835) | ($544,929,835) | ($544,929,835) | ($544,929,835) | ($544,929,835) |
| Investment Tax Credits | ($1,448,432) | ($1,448,432) | ($1,448,432) | ($1,448,432) | ($1,448,432) | ($1,448,432) | ($1,448,432) | ($1,448,432) | ($1,448,432) | ($1,448,432) |
| Other Rate Base Adjustments | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Other Items | ($546,378,267) | ($546,378,267) | ($546,378,267) | ($546,378,267) | ($546,378,267) | ($546,378,267) | ($546,378,267) | ($546,378,267) | ($546,378,267) | ($546,378,267) |
| **Rate Base** | $1,710,924,208 | $1,812,539,468 | $1,867,177,215 | $1,992,868,930 | $2,172,178,886 | $2,273,773,857 | $2,281,811,416 | $2,332,618,257 | $2,323,273,785 | $2,292,406,444 |

[redacted]

Duke Energy Ohio
Projected Operating and Maintenance Expenses
12 Months Ending 12/31

| O&M Forecast | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| [redacted] | | | | | | | | | | | |
| Total O&M Revenue Requirement | $228,615,837 | $242,707,354 | $249,190,587 | $248,593,326 | $261,709,210 | $235,460,171 | $256,908,670 | $261,233,019 | $265,460,276 | $269,593,837 | $273,418,520 |

[redacted]

Duke Energy Ohio
Projected Depreciation Expense
12 Months Ending 12/31

| Depreciation Forecast | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Beckjord | $0 | $0 | $0 | $0 | $0 | $0 | | | | | |
| Miami Fort | $17,327,931 | $17,388,372 | $17,300,916 | $17,263,401 | $17,561,324 | $17,518,870 | | | | | |
| Zimmer | $25,940,434 | $23,807,484 | $23,247,528 | $23,321,624 | $23,294,867 | $23,769,292 | | | | | |
| Conesville | $3,844,166 | $3,918,061 | $4,129,188 | $4,474,836 | $4,638,787 | $5,012,972 | | | | | |
| Killen | $4,102,177 | $4,140,740 | $4,092,125 | $4,070,806 | $4,066,329 | $4,084,804 | | | | | |
| Stuart | $19,981,915 | $20,228,048 | $19,924,167 | $20,460,505 | $21,439,074 | $22,494,224 | | | | | |
| Beckjord CT | $1 | $320 | $645 | $974 | $1,308 | $1,649 | | | | | |
| Dick's Creek | $193,407 | $193,528 | $193,897 | $193,885 | $193,873 | $193,860 | | | | | |
| Miami Fort CT | $0 | $0 | $0 | $0 | $0 | $0 | | | | | |
| Total Existing Depreciation | $71,390,021 | $68,687,551 | $68,888,465 | $69,786,030 | $71,195,463 | $73,085,671 | $73,085,671 | $73,085,671 | $73,085,671 | $73,085,671 | $73,085,671 |
| Incremental Depreciation on 2017 - 2020 Capex | | | | | | | $4,503,433 | $7,518,781 | $9,105,476 | $10,223,775 | $10,223,775 |
| Total Depreciation Current Plant | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Estimated Depreciation on Future Environmental Capex | $15,316 | $505,154 | $2,922,624 | $7,668,838 | $11,691,082 | $13,143,286 | $13,603,681 | $14,050,355 | $14,801,353 | $15,331,662 | $15,419,656 |
| Estimated Depreciation on Future Env Capex Ash Pond Closure | $0 | $0 | $0 | $0 | $0 | $0 | $625,291 | $3,182,735 | $8,834,348 | $13,061,693 | $13,863,489 |
| Other Depreciation (Software, Shared Services, Common Plant) | $11,922,822 | $10,553,933 | $6,902,975 | $7,512,304 | $5,415,240 | $4,432,385 | $4,432,385 | $4,432,385 | $4,432,385 | $4,432,385 | $4,432,385 |

# CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Projected Other Taxes
12 Months Ending 12/31

| Property Taxes | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| [redacted] | | | | | | | | | | | |
| Total Property Taxes | $13,397,958 | $14,330,292 | $14,410,044 | $14,657,292 | $15,113,664 | $13,074,367 | $13,270,483 | $13,469,540 | $13,671,583 | $13,876,657 | $14,084,807 |
| Payroll Taxes | $6,786,229 | $5,637,890 | $5,723,004 | $4,861,772 | $4,935,868 | $5,009,906 | $5,085,055 | $5,161,330 | $5,238,750 | $5,317,332 | $5,397,092 |
| Total Other Taxes | $20,184,187 | $19,967,682 | $20,133,048 | $19,519,064 | $20,049,532 | $18,084,273 | $18,355,537 | $18,630,870 | $18,910,333 | $19,193,988 | $19,481,898 |

Inflation Rate for Property and Payroll Taxes 1.50%

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Projected Cost of Purchased Capacity
12 Months Ending 12/31

| Capacity Short Position Forecast | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|
| [redacted] | | | | | | | | | | |

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Projected Retail Sales
12 Months Ending 12/31

| BAU Forecast (MWh) | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|
| [redacted] | | | | | | | | | | |

Duke Energy Ohio
Projected Net Book Value (Legacy Generation)
13 Months Ending 12/31

| Net Book Value Original Plant | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|

[redacted]

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Projected Capital Expenditures (Legacy Generation)
12 Months Ending 12/31

| Capital Expenditures Forecast | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| [redacted] | | | | | | | | | | | |

DUKE ENERGY OHIO EXHIBIT________

**BEFORE**

**THE PUBLIC UTILITIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service. | ) | Case No. 11-3549-EL-SSO |
| In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20. | ) | Case No. 11-3550-EL-ATA |
| In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Corporate Separation Plan. | ) | Case No. 11-3551-EL-UNC |

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**DIRECT TESTIMONY OF**

**ANDREW S. RITCH**

**ON BEHALF OF**

**DUKE ENERGY OHIO, INC.**

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June 20, 2011

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**PAGE**

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Andrew S. Ritch, and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed by Duke Energy Business Services LLC (DEBS) as the Director of Renewable Strategy and Compliance. DEBS provides various administrative and other services to Duke Energy Ohio, Inc., (Duke Energy Ohio or the Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

**Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I received a bachelor's degree in English from Colby College in Waterville, Maine, in 1993, and a master's degree in business administration from the F.W. Olin Graduate School of Business at Babson College, Wellesley, Massachusetts, in 2001. I began my career with Cinergy Corp. (Cinergy) in 2002, and have served both Cinergy, as well as the merged entity, Duke Energy, in a variety of capacities prior to my current role. These prior positions included Senior Analyst; Investor Relations; Director, Franchised Electric and Gas Strategy; and Director, Corporate Strategy.

**Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS THE DIRECTOR OF RENEWABLE STRATEGY AND COMPLIANCE.**

A. As the Director of Renewable Strategy and Compliance for Duke Energy's three franchised Midwest jurisdictions (Duke Energy Ohio; Duke Energy Kentucky, Inc.; and Duke Energy Indiana, Inc.) my primary responsibility is to lead the development, execution, and communication of the strategies for activities involving renewable energy in these states. My responsibilities also extend to the compliance obligations for renewable activities, including but not limited to development and implementation strategies to procure or build renewable resources to meet all regulatory and legislative requirements. I am also responsible for managing the interface between Duke Energy and key external stakeholders on matters pertaining to renewable energy and for directing the messages and policies pertaining to renewable energy.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?**

A. Yes. Earlier this year, I testified before the Public Utilities Commission of Ohio (Commission) in Case No. 10-2586-EL-SSO.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to discuss the alternative energy resource (AER) requirements of R.C. 4928.64 and, more specifically, Duke Energy Ohio's procurement practices and policies with respect to the renewable energy requirements of that statutory provision. In this regard, my testimony fulfills the filing requirement set forth in O.A.C. 4901:1-35-03(C)(9)(a). Finally, I address how the Company's plans for complying with the renewable energy requirements are consistent with and advance certain state policies.

## II. DISCUSSION

**Q. PLEASE DESCRIBE HOW THE COMPANY CURRENTLY ADDRESSES ITS ANNUAL ALTERNATIVE ENERGY COMPLIANCE OBLIGATIONS.**

A. To date, the Company has utilized renewable energy certificate (REC) purchases as the primary means of meeting its AER compliance obligations and has developed a portfolio of transactions with various parties to best assure that compliance can be achieved. The RECs that the Company has acquired for purposes of compliance have been obtained from multiple sources, including brokers, aggregators, and owners of renewable energy resources. The Company has endeavored to pursue a method of assuring compliance that is the most responsive to the expectations and requirements of the sellers of RECs; the most responsive to changes in market conditions; the most mindful of the regulatory and market risks associated with REC compliance; and the most likely to result in meeting the compliance requirements given the nascent nature of the renewable energy market in Ohio and surrounding jurisdictions. The Company has entered into agreements of various tenures, although most transactions have been relatively short-term in nature. The Company has recently implemented methods to supplement these shorter term REC transactions with longer term commitments of up to fifteen years in duration. The rationale for the Company's contracting strategy is described in further detail later in my testimony.

**Q. HOW WOULD YOU ASSESS THE COMPANY'S PERFORMANCE TO DATE RELATIVE TO ITS AER COMPLIANCE REQUIREMENTS?**

A. To date, the Company has performed quite well in terms of meeting its AER compliance requirements. This is not to say that there have not been challenges, but Duke Energy Ohio has risen to the challenge and has demonstrated sincere commitment to meet both the letter and the spirit of the state's policies regarding the development of renewable and advanced energy resources. Evidence of this includes the Commission's Opinion and Order in Case No. 10-511-EL-ACP. In the 2009 Alternative Energy Portfolio Status Report filed in that case, the Company demonstrated that it had met the 2009 AER compliance requirements, subject to certain findings by the Commission. This report also demonstrates that Duke Energy Ohio's methods of procuring RECs have been successful in obtaining the requisite quantities of RECs, even in certain categories such as the in-state (Ohio-based) solar category, which has been the most challenging component of the AER requirements to meet to date. The same argument holds true for Duke Energy Ohio's 2010 Alternative Energy Portfolio Status Report (PUCO Case No. 11-2515-EL-ACP), in which the Company has also demonstrated compliance, subject to certain findings by the Commission.

Additional evidence that Duke Energy Ohio's REC procurement strategy has been successful comes from Ohio's Clean Energy Report Card,[1] published by *Environment Ohio* in March 2011. In this publication, Duke Energy Ohio was praised for its compliance efforts, receiving an A grade by scoring 15.5 out of a possible 16 points. As the author of that Report Card concluded:

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[1] *Ohio's Clean Energy Report Card: How Wind, solar, and Energy Efficiency and Repowering the Buckeye State,* March, 2011 (http://www.environmentohio.org/uploads/ee/75/ee758efc7c57740d7f5f11833a8d1e0d/Ohios-Clean-Energy-Report-Card-web.pdf)

> Duke Energy (Ohio) led all Ohio utilities in its commitment to solar energy...Duke Energy (Ohio) in particular succeeded in incorporating a large amount of solar energy, obtaining the most solar electricity of any utility despite being only the third-largest utility in the state.

**Q. PLEASE DESCRIBE IN FURTHER DETAIL THE RATIONALE SUPPORTING THE CONTRACTING STRATEGY THAT THE COMPANY HAS UTILIZED TO DATE.**

A. As noted above, the Company has found its current methods of procuring RECs through brokers and aggregators, and directly from owners of renewable energy resources, to be effective. To execute on this strategy, the Company engages in frequent correspondence with various sellers and potential sellers of RECs. One primary reason for the effectiveness of this strategy is the flexibility and responsiveness that this affords. An alternative method, for purposes of making a contrasting example, would be a formal request for proposal (RFP) process. Although RFPs can be structured in many ways, they generally can be characterized as entailing specific dates for proposal submission and selection, along with specific requirements for sellers to meet in terms of performance, credit-worthiness, etc. Although RFPs have many merits, they tend to entail less flexibility for both the utility and the counterparties. Given the nascent nature of the market and the ongoing process of obtaining a clearer understanding of regulatory requirements, Duke Energy Ohio has placed a high value on the flexibility afforded by its current strategy and its overall effectiveness. As I will explain in greater detail later, the Company has considered, and continues to consider, RFPs as another viable method to meet compliance and may implement this tactic as appropriate in the future. My purpose here was simply to illustrate some differences between compliance tactics and explain the rationale for the tactics that Duke Energy Ohio has implemented to date.

**Q. WHAT FACTORS HAS THE COMPANY CONSIDERED IN DETERMINING THE TENURE, OR DURATION, OF THE CONTRACTUAL COMMITMENTS THAT IT HAS ENTERED INTO?**

A. Broadly speaking, the factors that the Company considers in this regard are need and risk.

With respect to need, the Company considers the availability of RECs in the market in relation to the size of the Company's AER requirements. Availability of RECs is influenced by many factors, including the price the Company is willing to pay and the term of the contract it is willing to enter into. Meanwhile, the size of the AER requirement is determined by sales to customers and the corresponding percentage requirement, as set forth in R.C. 4928.64.

With respect to risk, the Company considers many factors, including any cost recovery risks and the uncertainty of the availability and cost of RECs in future periods as compared to the present. Cost recovery risk is present due to the short-term nature of the Company's current Electric Security Plan (ESP) and the associated Rider PTC-FPP through which compliance costs are presently recovered, both of which are scheduled to expire on December 31, 2011, as well as the capability that customers have to switch to alternative generation providers. Although customer choice is understood to be a fundamental tenet of the state's energy policy, it introduces a risk associated with long-term REC purchases since the revenue from customers that the Company can count on to support such purchases is inherently short term in nature. As discussed by Duke Energy Ohio witness Julia S. Janson, the Company has experienced substantial customer switching in recent years and, thus, the Company is quite mindful of the need to match, to the extent possible, the cash outflows for REC purchases with the revenue that can be counted on from customers. This has led Duke Energy Ohio to favor shorter term REC transactions to the extent possible and practical.

Additionally, there is uncertainty regarding the availability and price of RECs in the future as compared to today. Many renewable energy technologies are experiencing significant advances in cost effectiveness, and as development of renewable resources continues, the Company is mindful that it may be possible to contract for the purchase of RECs at more cost effective prices in the future.

The continued improvement in the cost of renewable energy was also contemplated in the structure of Amended Substitute Senate Bill 221 (S.B. 221), as evidenced by the declining alternative compliance payment (ACP) for solar resources. The Company's experience to date suggests that the combination of technological innovation and the legislative structure of S.B. 221 could result in greater cost effectiveness in the procurement of RECs in the future as compared to today. This notion simply informs the Company's contracting strategy as it contemplates how to meet its AER requirements in the most economic manner possible.

Taken together, as Duke Energy Ohio has considered both its need for RECs through time and the various risks involved with different tactics that could be employed to procure those RECs, it has, to date, employed a strategy characterized primarily by shorter term REC contracts. As noted, this has been successful in obtaining the requisite quantities of RECs while remaining mindful of the various risks that I have noted. Going forward, the Company will continue to evaluate both of these factors (need and risk) and will implement new tactics to assure compliance with the AER requirements.

**Q. YOU NOTED THAT THE COMPANY HAS RELIED PRIMARILY ON SHORTER TERM REC TRANSACTIONS FOR COMPLIANCE TO DATE. WILL YOU DESCRIBE ANY EFFORTS THAT RELATE TO LONGER TERM REC PURCHASES?**

A. Yes. Duke Energy Ohio has recently implemented a residential solar REC purchase program. This program is filed under Case No. 09-834-EL-ACP. Under the program, the Company has committed to purchasing solar RECs from residential customers for a term of fifteen years. This program was a product of the settlement of the Company's current ESP. After negotiation with various interested parties, this program was developed and approved by the Commission. The Company believes that this program represents an innovative and important component of the Company's compliance actions; however, given the modest customer response to date, the anticipated contribution from this program toward meeting Duke Energy Ohio's in-state solar requirements is expected to be minimal.

**Q. PLEASE DESCRIBE THE COMPANY'S PLAN – UNDER ITS PROPOSED ESP – FOR COMPLYING WITH THE ALTERNATIVE ENERGY REQUIREMENTS OF S.B. 221.**

A. The Company plans to employ any and all reasonable methods to assure compliance with the AER requirements in S.B. 221. The specific tactics employed will be adjusted through time, as needed. The Company believes that maintaining flexibility in the choice of compliance strategies is necessary to provide the greatest certainty of compliance, and to assure that the most cost-effective methods are implemented for the benefit of customers. In selecting the appropriate compliance tactics to employ, the Company will consider various factors that I have addressed in this testimony, including the size of the Company's requirements through time, the availability of RECs at various prices and contract terms, and various risks noted previously.

More specifically, the Company intends to continue the pursuit of its current successful strategy of procuring RECs through brokers and aggregators, and directly from owners of renewable energy resources. Duke Energy Ohio will continue to favor shorter term REC contracts for the reasons I have noted previously, but the Company recognizes that it may be necessary to supplement this tactic with longer term transactions to adequately assure that the compliance targets are met. In addition to implementing longer term transactions, as needed, the Company will consider supplementing its current successful strategy with the issuance of periodic RFPs for RECs. As the compliance obligations grow through time, Duke Energy Ohio recognizes that multiple tactics will likely be needed and that there could very well be a need to introduce into our strategy the issuance of periodic RFPs for RECs, which could result in less administrative burden and could reach additional sellers of RECs. Furthermore, the Company will consider implementing additional structured programs of various types, along the lines of the residential REC purchase program, to further enhance the certainty of compliance.

In summary, Duke Energy Ohio is committed to meeting the AER compliance requirements and will utilize all reasonable methods deemed necessary to assure that goal is accomplished. The Company's base plan for compliance is the continuation of its existing successful approach, and will be supplemented with additional tactics, as necessary. Duke Energy Ohio understands and observes that S.B. 221 creates a strong motivation for achieving compliance, and the Company is committed to doing so.

**Q. HOW DOES THE COMPANY'S PROPOSED ESP ADVANCE THE DEVELOPMENT OF THE RENEWABLE ENERGY MARKET IN OHIO?**

A. The Company's proposed ESP is a long-term plan that offers customers and the Company stability and certainty in terms of both the structure of the SSO and its duration. This certainty, in turn, allows the Company to plan further into the future, which may offer greater flexibility to meet its AER obligation.

**Q. WHAT BENEFITS ARE AVAILABLE TO DUKE ENERGY OHIO AS A RESULT OF THE COSTS ASSOCIATED WITH MEETING THE AER OBLIGATION?**

A. Benefits to the Company include the ability to provide a source of capacity from cleaner and more affordable generation and to support the development of alternative energy resources in the state. Also, compliance with the AER mandates dovetails with Duke Energy's corporate goal of increasing our renewable generation capacity.

Finally, the economic stimulus provided by requiring generation from renewable resources provides jobs within the state that would not otherwise develop in the existing economic environment. A more robust economy allows the Company to serve more customers. These are all benefits to the Company from its compliance with AER mandates.

**Q. WHAT BENEFITS ARE AVAILABLE TO DUKE ENERGY OHIO AS A RESULT OF THE COSTS ASSOCIATED WITH MEETING THE AER OBLIGATION?**

A. Benefits to the Company include the ability to provide a source of energy from cleaner and more affordable generation and to support the development of alternative energy resources in the state. Compliance with the AER mandates supports Duke Energy's corporate goal of increasing the Company's renewable generation. Finally, the Company is afforded the benefit of a reasonable assurance of recovering the costs it incurs to meet the AER mandates.

**Q. HOW IS THE COMPANY PROPOSING TO RECOVER THE COST OF COMPLYING WITH THE STATE'S RENEWABLE ENERGY STANDARDS AFTER DECEMBER 31, 2011?**

A. As described in the testimony of Duke Energy Ohio witness James E. Ziolkowski, upon the effective date of the ESP, the Company will begin recovering costs for purchasing RECs and for any other costs for complying with the alternative energy standards via its new Rider AER-R (alternative energy recovery rider). This recovery mechanism is similar to existing Rider PTC-FPP (price-to compare: fuel and purchased power), but provides more transparency for customers as the AER compliance costs will no longer be included in the rider used to recover fuel and purchased power. Only those costs specific to AER compliance will be recovered through the proposed Rider AER-R.

**Q. PLEASE EXPLAIN HOW DUKE ENERGY OHIO'S AER COMPLIANCE PLAN ADVANCES OF STATE POLICY.**

A. The plan advances of state policy, as defined within R.C. 4928.02, with particular relevance to divisions C, J, and M.

> *It is the policy of this state to do the following throughout this state:*
>
> *(C) Ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies and suppliers and by encouraging the development of distributed and small generation facilities;*

This sub-section highlights two important objectives of state policy: customer choice, and the development of distributed and small generation facilities. The Company's plan to meet its AER requirements is supportive of both of these objectives.

First, with regards to customer choice, customers will retain the option of obtaining generation resources through the Company's standard service offer or through alternative suppliers. If customers elect service through the Company's standard service offer, Duke Energy Ohio must procure the RECs associated with that customer's usage, and it will do so through the methods described previously. If, however, the customer elects service from an alternative supplier, that alternative supplier would assume the responsibility to meet the AER requirements that correspond to that customer's usage.

Second, the Company's plan is also supportive of the state policy to promote the development of distributed and small generation facilities. Most renewable resources are both distributed and small in nature, so it should be evident that procurement of the requisite RECs to meet the Company's compliance obligations, which is the Company's plan and intent, will support this state policy. All RECs are linked to specific renewable energy assets, and the Company's efforts to purchase RECs will inherently stimulate the development of these resources. One specific example that is a clear illustration of how our efforts will support this state policy is the residential REC purchase program, which is very specifically focused on small and distributed generation resources.

*(J) Provide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential environmental mandates;*

The Company's plan is also supportive of this state policy. It should be evident that renewable energy resources are among the best qualified generation technologies to thrive under potential environmental mandates. As such, the Company's plan to purchase RECs from customer-generators or owners of renewable generating assets provides a clear, coherent and market-based economic signal in the form of direct cash payments in exchange for RECs, which is consistent with the stated objective of this sub-section.

> *(M) Encourage the education of small business owners in this state regarding the use of, and encourage the use of, energy efficiency programs and alternative energy resources in their businesses;*

As a buyer of RECs, the Company's plan stimulates investment in renewable energy projects because it provides for a reliable, long-term outlet for RECs at market prices in return for monetary payment. In this way, the plan encourages small business owners to learn about and utilize renewable energy resources in their businesses because of the financial benefit to install these systems (in addition to tax credits, accelerated depreciation and the value of the displaced energy). Renewable energy and energy efficiency are linked, as the installation of renewable generating resources often follows thorough assessments of a business facility's overall energy efficiency, with actions taken to reduce usage. In essence, the value of the RECs generated provides an additional financial incentive to businesses.

## III. CONCLUSION

**Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

DUKE ENERGY OHIO EXHIBIT _____

**BEFORE**

**THE PUBLIC UTILITIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service. | ) | Case No. 11-3549-EL-SSO |
| In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20. | ) | Case No. 11-3550-EL-ATA |
| In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Corporate Separation Plan. | ) | Case No. 11-3551-EL-UNC |

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**DIRECT TESTIMONY OF**

**ROGER A. MORIN Ph.D.**

**ON BEHALF OF**

**DUKE ENERGY OHIO, INC.**

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June 20, 2011

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## I. <u>INTRODUCTION</u>

**Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.**

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia 30303. I am Emeritus Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

**Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.**

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet, Inc., where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last thirty years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and on "Utility Capital

Allocation," which I have developed on behalf of The Management Exchange, Inc., and Exnet (now SNL Energy) in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utilities Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released Regulatory Finance, a voluminous treatise I wrote on the application of finance to regulated utilities. A revised and expanded edition of this book entitled The New Regulatory Finance was published in August 2006. I have engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. Exhibit RAM-1 describes my professional credentials in more detail.

**Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?**

A. Yes, I have been a cost of capital witness before nearly fifty (50) regulatory bodies in North America, including the Public Utilities Commission of Ohio (PUCO or the Commission), the Federal Energy Regulatory Commission, and the Federal Communications Commission. Below is a comprehensive list of the state, provincial, and other local regulatory commissions to which I have provided testimony:

| | | | |
|---|---|---|---|
| Alabama | Florida | Missouri | Ontario |
| Alaska | Georgia | Montana | Oregon |
| Alberta | Hawaii | Nevada | Pennsylvania |
| Arizona | Illinois | New Brunswick | Quebec |
| Arkansas | Indiana | New Hampshire | South Carolina |
| British Columbia | Iowa | New Jersey | South Dakota |
| California | Kentucky | New Mexico | Tennessee |
| City of New Orleans | Louisiana | New York | Texas |
| Colorado | Maine | Newfoundland | Utah |
| CRTC | Manitoba | North Carolina | Vermont |
| Delaware | Maryland | North Dakota | Virginia |
| District of Columbia | Michigan | Nova Scotia | Washington |
| FCC | Minnesota | Ohio | West Virginia |
| FERC | Mississippi | Oklahoma | |

Details of my participation in regulatory proceedings are provided in Exhibit RAM-1.

**Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my direct testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on common equity (ROE) on the capital invested in the generation capacity component of Duke Energy Ohio, Inc.'s (Duke Energy Ohio or Company) electric utility operations of in the state of Ohio. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to the ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion.

This testimony and accompanying exhibits and appendices were prepared by me or under my direct supervision and control. The source documents for my testimony are Company records, public documents, commercial data sources, and my personal knowledge and experience.

**Q. PLEASE BRIEFLY IDENTIFY THE EXHIBITS AND APPENDICES ACCOMPANYING YOUR TESTIMONY.**

A. I have attached to my testimony Exhibits RAM-1 through RAM-7 and Appendices A and B. These Exhibits and Appendices relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony. A listing of my Exhibits and Appendix is provided below:

| | |
|---|---|
| Exhibit RAM-1 | Resume of Roger A. Morin |
| Exhibit RAM-2 | Electric Utility Beta Estimates |
| Exhibit RAM-3 | S&P Utility Common Stocks Over Long-Term Treasury Bonds Annual Long-Term Risk Premium Analysis |
| Exhibit RAM-4 | Integrated Electric Utilities DCF Analysis: Value Line Growth Projections |
| Exhibit RAM-5 | Integrated Electric Utilities DCF Analysis: Analysts' Growth Forecasts |
| Exhibit RAM-6 | S&P's Electric Utilities DCF Analysis: Value Line Growth Forecasts |
| Exhibit RAM-7 | S&P's Electric Utilities DCF Analysis: Analysts' Growth Forecasts |
| Appendix A | CAPM, Empirical CAPM |
| Appendix B | Flotation Cost Allowance |

**Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING DUKE ENERGY OHIO'S RETURN ON COMMON EQUITY CAPITAL.**

A. It is my opinion that a just and reasonable ROE for Duke Energy Ohio's investment in generation capacity is 10.75%. My recommendation is derived from studies I performed using the Capital Asset Pricing Model (CAPM), Risk Premium, and Discounted Cash Flow (DCF) methodologies. I performed two CAPM analyses: a "traditional" CAPM and a methodology using an empirical approximation of the CAPM (ECAPM). I performed two historical risk premium analyses on the electric utility industry, one based on historical data, the other on returns allowed by regulators. I also performed DCF analyses on two surrogates for the Company's electric utility business. They are: a group of investment-grade integrated electric utilities, and a group consisting of the electric utilities that make up Standard & Poor's Utility Index, representative of the industry.

My recommended rate of return reflects the application of my professional judgment to the indicated returns from my CAPM, Risk Premium, and DCF analyses.

**Q. WOULD IT BE IN THE BEST INTERESTS OF RATEPAYERS FOR THE COMMISSION TO ADOPT YOUR RECOMMENDED 10.75% RETURN ON EQUITY FOR DUKE ENERGY OHIO'S ELECTRIC GENERATION CAPACITY?**

A. Yes. My analysis shows that a ROE of 10.75% is required to fairly compensate investors, maintain the Company's credit strength, and attract the capital needed for utility infrastructure and environmental compliance capital investments.

Adopting a lower ROE would jeopardize the Company's stability and its ability to provide for the reliability of supply required by its customers.

**Q. PLEASE EXPLAIN HOW A LOW AUTHORIZED ROE CAN INCREASE COSTS FOR RATEPAYERS.**

A. If a utility is authorized a ROE below the level required by equity investors, regardless of their identity, the utility will find it difficult to access the equity market through common stock issuance at its current market price. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a utility that has been authorized a return below the level that investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This reduces the financial viability of equity financing in two ways. First, because the utility's price per share of common stock decreases, the net proceeds from issuing common stock are reduced. Second, because the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

As the utility relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth. Consequently, equity investors face even greater uncertainty about future dividends and earnings from the utility. As a result, the utility's equity becomes a riskier investment. The risk of default on the company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that Duke Energy Ohio has access to capital markets for its capital needs through its parent company, a fair and reasonable authorized ROE of 10.75% is required.

It is imperative the Company have access to capital funds at reasonable terms and conditions. The Company must secure outside funds from capital markets to finance required utility plant and equipment investments irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Therefore, rate relief requirements and supportive regulatory treatment, including approval of my recommended ROE, are essential requirements.

**Q. DR. MORIN, PLEASE DESCRIBE HOW THE REST OF YOUR TESTIMONY IS ORGANIZED.**

A. In Section II, I address the regulatory framework and rate of return. This section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. In Section III, I present cost of equity estimates. This section contains the application of CAPM, Risk Premium, and DCF tests. In Section IV, I provide my summary and recommendation.

## II. REGULATORY FRAMEWORK AND RATE OF RETURN

**Q. DR. MORIN, WHAT IS YOUR UNDERSTANDING REGARDING HOW DUKE ENERGY OHIO IS PROPOSING TO ESTABLISH ITS CAPACITY COSTS IN THIS PROCEEDING?**

A. My understanding is that Duke Energy Ohio is seeking to establish a price for capacity that is based upon the Company's actual embedded cost of service, with certain adjustments, which includes a return based on my recommendation of an ROE, in a manner similar to that of a more traditional cost of service paradigm, while still maintaining a fully competitive market for energy. The direct testimony of Duke Energy Ohio witness William Don Wathen Jr., explains Duke Energy Ohio's cost recovery proposal in that regard.

**Q. PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET UNDER TRADITIONAL COST OF SERVICE PRINCIPLES.**

A. Under the traditional ratemaking process, a utility's rates are set so that the company recovers its costs, including income taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of the next section of my testimony to estimate Duke Energy Ohio's cost of common equity capital.

**Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE ROE?**

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).
2. Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944).

The Bluefield case set the standard against which just and reasonable rates of return are measured:

> *A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties ... The return should be*

> *reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.* (Emphasis added.)

The Hope case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the Bluefield case and recognized that revenues must cover "capital costs." The Court stated:

> *From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock ... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.* (Emphasis added.)

The United States Supreme Court reiterated the criteria set forth in Hope in Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory agency's rate of return order should:

> *"...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed...."*

Therefore, the "end result" of the Commission's decision should be to allow Duke Energy Ohio the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the Company's financial integrity, and (3) sufficient to maintain the Company's creditworthiness and ability to attract capital on reasonable terms.

**Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?**

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility. It is the composite weighted cost of the various classes of capital (*i.e.*, bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

Utilities like Duke Energy Ohio, operating in jurisdictions that have embraced retail competition in the sale of public utility services, must compete with everyone else in the free, open market for the input factors of production, whether they be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This item is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected market return on common and/or preferred equity.

**Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?**

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they also are exposing their funds to risk and forgoing returns from investing their money in alternative comparable-risk investments. The compensation that they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. These differences in risk are translated by the capital markets into price differences in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for the respective securities and the risks expected from the overall menu of available securities. Because utility debt and equity investors receive their returns on a different basis, have different types of investment objectives, and are affected in different ways by external market and company factors, their risks are quite dissimilar.

**Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF DUKE ENERGY OHIO'S COST OF COMMON EQUITY?**

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity, one relating to the supply side of capital markets and the other to the demand side.

On the supply side, the first principle asserts that rational investors maximize the performance of their portfolios only if they expect the returns earned on investments of comparable risk to be the same. If not, rational investors will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk.

On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

**Q. WHAT SOURCES OF CAPITAL ARE EMPLOYED BY THE COMPANY AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?**

A. The funds employed by the Company are obtained in two general forms, debt capital and equity capital. The latter consists of common equity capital. The cost of debt funds can be ascertained easily from an examination of the contractual terms for the interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments.

Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt, based on the utility's capital structure, in order to arrive at the overall cost of capital.

**Q. WHAT IS THE MARKET REQUIRED ROE?**

A. The market required ROE, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments, and the returns available from other investments of comparable risk.

**Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR ROE?**

A. The basic premise is that the allowable ROE should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness, and ability to attract capital on reasonable terms. The attraction of capital standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, CAPM, or DCF methods. These market value tests define fair return as the return that investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This return is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternative investments of comparable risk.

**Q. HOW DOES DUKE ENERGY OHIO'S COST OF CAPITAL RELATE TO THAT OF ITS ULTIMATE PARENT COMPANY, DUKE ENERGY?**

A. I am treating Duke Energy Ohio as a separate stand-alone entity, distinct from its parent company Cinergy and distinct from the ultimate parent company Duke Energy Corp. (Duke Energy), because it is the cost of capital for Duke Energy Ohio's generation capacity component that we are attempting to measure and not the cost of capital for Duke Energy's consolidated activities. Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost to the investor, in this case, Duke Energy. The true cost of capital depends on the use to which the capital is put, in this case Duke Energy Ohio's electric generation business. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost but, rather, the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return for Duke Energy Ohio is the return foregone in comparable risk investments, and is unrelated to the parent's cost of capital and the distribution/transmission businesses as these have ROEs set under different circumstances. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity, be it either individual investors or a parent holding company.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as for long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Thus, the cost of investing funds in an electric utility, such as Duke Energy Ohio, operating in a competitive generation market such as Ohio, is the return foregone on investments of similar risk and is unrelated to the investor's identity.

## III. COST OF EQUITY ESTIMATES

**Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR ROE FOR DUKE ENERGY OHIO?**

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to Duke Energy Ohio's electric utility business. I have applied the aforementioned methodologies to two samples of electric utilities comparable in risk to Duke Energy Ohio.

**Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?**

A. No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

As I have stated, there are three broad generic methodologies available to measure the cost of equity: CAPM, Risk Premium, and DCF. All three of these methodologies are accepted and used by the financial community and firmly supported in the financial literature. The weight accorded to any one methodology may very well vary depending on unusual circumstances in capital market conditions.

Each methodology requires the exercise of considerable judgment concerning the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology, especially in the current atmosphere of turmoil and volatility in capital markets. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component, are vivid examples of the potential shortcomings of the DCF model.

Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of a stock's price or the cost of equity.

**Q. ARE THERE ANY PRACTICAL DIFFICULTIES IN APPLYING COST OF CAPITAL METHODS IN THE CURRENT ENVIRONMENT OF VOLATILITY IN CAPITAL MARKETS?**

A. Yes, there are. All the traditional cost of equity estimation methods are difficult to implement when you are dealing with the unprecedented conditions of instability and volatility in the capital markets and the fast-changing circumstances of the utility industry. This is not only because stock prices are extremely volatile at this time, but also utility company historical data has become less meaningful for an industry experiencing unprecedented volatility. Past earnings and dividend trends may simply not be indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors including structural transformation, restructuring, and the transition to a more competitive environment and, like in Ohio, availability of customer choice and significant switching. Moreover, historical growth rates may not be representative of future trends for several utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data is available.

Q. **DR. MORIN, PLEASE PROVIDE AN OVERVIEW OF YOUR RISK PREMIUM ANALYSES.**

A. In order to quantify the risk premium for Duke Energy Ohio, I performed four risk premium studies. The first two studies deal with aggregate stock market risk premium evidence using two versions of the CAPM methodology, and the other two deal directly with the utility industry.

## A. <u>CAPM ESTIMATES</u>

Q. **PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.**

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. Simply put, the idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by $R_F$ and the return on the securities market as a whole by $R_M$, the CAPM is:

$$K = R_F + \beta\ (R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, $R_F$, plus a risk premium determined by $\beta(R_M - R_F)$. The latter bracketed expression is known as the market risk premium (MRP). To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate ($R_F$), beta ($\beta$), and the MRP, ($R_M - R_F$). For the risk-free rate, I used 5.0% based on the current and anticipated level of long-term Treasury interest rates. For beta, I used 0.72 and for the MRP, I used 6.7%. These inputs to the CAPM are explained below.

**Q. HOW DID YOU ARRIVE AT THE RISK FREE RATE OF 5.0%?**

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the current level of 30-year Treasury bond yields and on forecasts which call for a rising trend in interest rates in response to the recovering economy and record high federal deficits.

The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term or intermediate-term Treasury notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely. Thus, the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an investor's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments. Thus the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM.

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (*e.g.*, pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

Another reason for utilizing the longest maturity Treasury bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return therefore will be equal to the inflation rate anticipated to prevail over the very long-term. The same expectation should be embodied in the risk free rate used in applying the CAPM model. It stands to reason that the actual yields on 30-year Treasury bonds will more closely incorporate within their yield the inflation expectations that influence the prices of common stocks than do short-term or intermediate-term U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yield on such securities should be used as proxies for the risk-free rate in applying the CAPM, provided there are no anomalous conditions existing in the 30-year Treasury market. In the absence of such conditions, I have relied on the yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

**Q. DR. MORIN, ARE THERE OTHER REASONS WHY YOU REJECT SHORT-TERM INTEREST RATES AS PROXIES FOR THE RISK-FREE RATE IN IMPLEMENTING THE CAPM?**

A. Yes. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, as was seen since the commencement of the financial crisis, Treasury Bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes no sense to match the return on common stock to the yield on 90-day Treasury Bills. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

**Q. WHAT IS YOUR ESTIMATE OF THE RISK-FREE RATE IN APPLYING THE CAPM?**

A. The level of U.S. Treasury 30-year long-term bonds prevailing in March 2011 as reported in Value Line is 5.0%. I note that interest rate forecasts from Value Line, Blue Chip, and Consensus Forecasts all indicate rising rates over the next several years in response to record high federal deficits and economic recovery. Accordingly, I use 5.0% as my estimate of the risk-free rate component of the CAPM.

**Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?**

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta," or "systematic risk." The beta coefficient measures the change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. The beta coefficient indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and, thus, measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation that are reflected in investors' return requirements.

As a wholly-owned subsidiary of Duke, Duke Energy Ohio is not publicly traded and, therefore, proxies must be used. In the discussion of DCF estimates of the cost of common equity below, I discuss the issue of constructing groups of companies comparable in risk to the Company's generation business. Specifically, I examine a sample of widely-traded investment-grade dividend-paying integrated electric utilities covered by Value Line that have (i) at least 50% of their revenues from regulated utility operations, and (ii) a market capitalization that is more than $500 million.[1] The average beta for this group is currently 0.72. Please see Exhibit RAM-2 page 1 for the betas of this sample of utilities.

As a second proxy for Duke Energy Ohio's beta, I examined the average beta of the electric utility companies that make up Standard & Poor's Electric Utility Index. The average beta for the group is 0.73. If we remove the companies with less than 50% of their revenues from regulated electric utility operations, the average beta of the remaining companies is 0.71. Please see Exhibit RAM-2 page 2 for the betas of the electric utilities in the S&P's Electric Utility Index.

Based on these results, I shall use the average of the three estimates, 0.72, as a reasonable estimate applicable to Duke Energy Ohio's generation operations. It is important to note that betas are estimated on five-year historical periods and, therefore, do not capture the re-pricing of risk and the increase in volatility and capital costs that followed the October 2008 – December 2009 period.

**Q. WHAT MRP ESTIMATE DID YOU USE IN YOUR CAPM ANALYSIS?**

A. For the MRP, I used 6.7%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums, mainly the

[1] This is necessary in order to minimize the well-known thin trading bias in measuring beta. For securities for which there is only periodic trading, beta estimates are downward biased. This is because observed returns contain stale information about past period returns rather than current period returns. Intuitively, if the stock market index surges forward but an individual company stock price remains unchanged due to lack of trading, the estimated beta is imparted a downward bias.

latter. First, the Morningstar (formerly Ibbotson Associates) study, Stocks, Bonds, Bills, and Inflation, 2011 Yearbook, compiling historical returns from 1926 to 2010, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 6.0%. The historical MRP over the income component of long-term Treasury bonds rather than over the total return is 6.7%. Morningstar recommends the use of the latter as a more reliable estimate of the historical MRP, and I concur with this viewpoint. The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. This is because the income component of total bond return (*i.e.*, the coupon rate) is a far better estimate of expected return than the total return (*i.e.*, the coupon rate + capital gain), as realized capital gains/losses are largely unanticipated by bond investors. The long-horizon (1926-2010) MRP (based on income returns, as required) is specifically calculated to be 6.7% rather than 6.0%.

**Q. ON WHAT MATURITY BOND DOES THE MORNINGSTAR HISTORICAL RISK PREMIUM DATA RELY?**

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2010 period covered in the Morningstar study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. Given that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Morningstar study, the difference in yield is not material.

**Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MRP ESTIMATE?**

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the MRP with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, because they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate MRP minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a "random walk," the best estimate of the future risk premium is the historical mean. Because I found no evidence that the MRP in common stocks has changed over time (at least until now), that is, no significant serial correlation in the Morningstar study, it is reasonable to assume that these quantities will remain stable in the future.

**Q. DID YOU BASE YOUR MRP ESTIMATE ON ANY OTHER SOURCE?**

A. Yes, I did. I applied a prospective DCF analysis to the aggregate equity market using Value Line's VLIA software. The dividend yield on the dividend-paying stocks that make up the Value Line Composite Index is currently 2.4% (VLIA 03/2011 edition), and the average projected long-term growth rate is 8.96%. Adding the dividend yield to the growth component produces an expected market return on aggregate equities of 11.36%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 11.58%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings the MRP estimate to approximately 11.78%. Subtracting the risk-free rate of 5.0% from the latter, the implied risk premium is 6.8% over long-term U.S. Treasury bonds. This estimate is virtually identical to the historical estimate of 6.7%, corroborating its reasonableness.

As a further check on the MRP estimate, I also examined a 2003 comprehensive article published in Financial Management (see Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66).

These authors provide estimates of the prospective expected market returns for S&P 500 companies. They measure the expected market rate of return of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. The prevailing risk-free rate for each year was then subtracted from the expected rate of return for the overall market to arrive at the market risk premium for that year. The average MRP estimate from that study for the overall period is 7.2%, which is reasonably close to my own estimate of 6.7%.

**Q. DR. MORIN, IS YOUR MRP ESTIMATE OF 6.7% CONSISTENT WITH THE ACADEMIC LITERATURE ON THE SUBJECT?**

A. Yes, it is. In their authoritative corporate finance textbook, Professors Brealey, Myers, and Allen[2] conclude from their review of the fertile literature on the MRP that a range of 5% to 8% is reasonable for the MRP in the United States. My own survey of the MRP literature, which appears in Chapter 5 of my latest textbook, The New Regulatory Finance, is also quite consistent with this range.

**Q. WHAT IS YOUR RISK PREMIUM ESTIMATE OF DUKE ENERGY OHIO'S COST OF EQUITY USING THE CAPM APPROACH?**

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 5.0%, a beta of 0.72, and a MRP of 6.7%, the CAPM estimate of the cost of common equity for Duke Energy Ohio is: 5.0% + 0.72 x 6.7% = 9.8%. This estimate becomes 10.1% with flotation costs, discussed later in my testimony.

**Q. CAN YOU DESCRIBE YOUR APPLICATION OF THE EMPIRICAL VERSION OF THE CAPM?**

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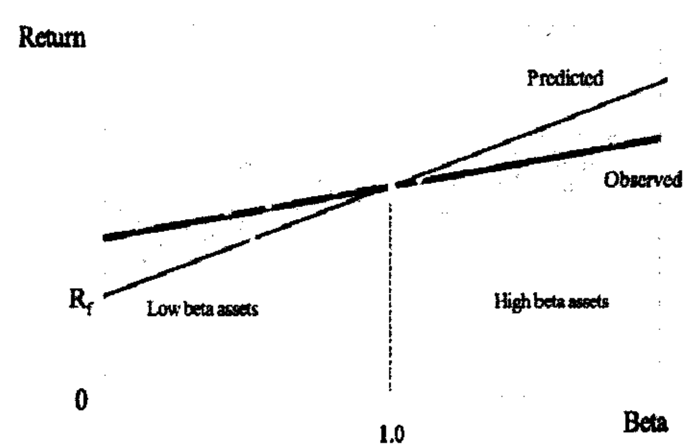
[2] Richard A. Brealey, Stewart C. Myers, and Paul Allen, Principles of Corporate Finance, 8th Edition, Irwin McGraw-Hill, 2006.

A. There have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 13 of my 1994 book, Regulatory Finance, and Chapter 6 of my latest book, The New Regulatory Finance, both published by Public Utilities Report Inc. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

**CAPM: Predicted vs Observed Returns**



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \acute{\alpha} + \beta \times (MRP - \acute{\alpha})$$

where the symbol alpha prime, $\acute{\alpha}$, represents the "constant" of the risk-return line, MRP is the market risk premium ($R_M - R_F$), and the other symbols are defined as usual.

Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. In other words, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version that has been tested. This is also because the use of adjusted betas rather than the use of raw betas incorporates some of the desired effect of using the ECAPM[3]. Thus, it is

[3] The regression tendency of betas to converge to 1.0 over time is very well known and widely discussed in the financial literature. As a result of this beta drift, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. Value Line, Bloomberg, and Merrill Lynch betas are

reasonable to apply a conservative alpha adjustment.

Appendix A contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings. In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta\,(R_M - R_F)$$

Inserting 5.0% for the risk-free rate $R_F$, a MRP of 6.7% for $(R_M - R_F)$ and a beta of 0.72 in the above equation, the ROE is 10.3%. This estimate becomes 10.6% with flotation costs, discussed later in my testimony.

**Q. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF ADJUSTED BETAS?**

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line. Such critics argue that the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the observed return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate

adjusted for their long-term tendency to regress toward 1.0 by giving approximately 66% weight to the measured raw beta and approximately 33% weight to the prior value of 1.0 for each stock.

features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas, as explained in Appendix A.

**Q. PLEASE SUMMARIZE YOUR CAPM ESTIMATES.**

A. The table below summarizes the common equity estimates obtained from the CAPM studies.

| METHOD | % ROE |
|---|---|
| Traditional CAPM | 10.1% |
| Empirical CAPM | 10.6% |

## B. HISTORICAL RISK PREMIUM ESTIMATE

**Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE ELECTRIC UTILITY INDUSTRY.**

A. My analysis of the historical risk premium for the electric utility industry was estimated with an annual time series analysis applied to the utility industry as a whole over the 1930-2010 period, using *Standard and Poor's Utility Index* as an industry proxy. The analysis is depicted on Exhibit RAM-3. The risk premium was estimated by computing the actual realized return on equity capital for the S&P Utility Index for each year, and then subtracting the long-term Treasury bond return for that year.

As shown on Exhibit RAM-3, the average risk premium over the period was 5.7% over long-term Treasury bond yields. Given that the current yield on long-term Treasury bonds is 5.0%, and using the historical estimate of 5.7%, the implied cost of equity for the average risk utility from this particular method is 5.0% + 5.7% = 10.7% without flotation costs and 11.0% with the flotation cost allowance. The need for a flotation cost allowance is discussed at length later in my testimony.

**Q. DR. MORIN, ARE RISK PREMIUM STUDIES WIDELY USED?**

A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, economists, and expert witnesses. Most college-level corporate finance and/or investment management texts, including Investments by Bodie, Kane, and Marcus, McGraw-Hill Irwin, 2002, which is a recommended textbook for CFA (Chartered Financial Analyst) certification and examination, contain detailed conceptual and empirical discussion of the risk premium approach. The latter is typically recommended as one of the three leading methods of estimating the cost of capital. Professor Brigham's best-selling corporate finance textbook, for example, Corporate Finance: A Focused Approach, 4th ed., South-Western, 2011, recommends the use of risk premium studies, among others. Techniques of risk premium analysis are widespread in investment community reports. Professional certified financial analysts are certainly well versed in the use of this method.

**Q. ARE YOU CONCERNED ABOUT THE RESTRICTIVENESS OF THE ASSUMPTIONS THAT UNDERLIES THE HISTORICAL RISK PREMIUM METHODOLOGY?**

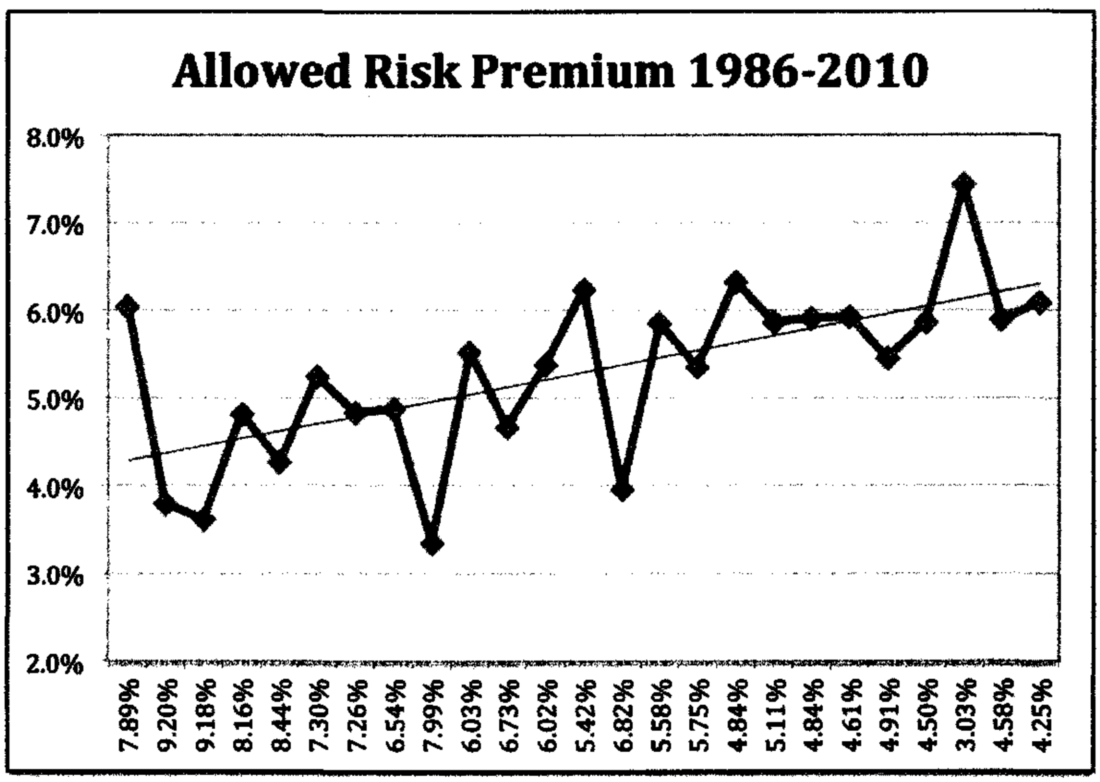
A. No, I am not, for they are no more restrictive than the assumptions that underlie the DCF model or the CAPM. While it is true that the method looks backward in time and assumes that the risk premium is constant over time, these assumptions are not necessarily restrictive. By employing returns realized over long time periods rather than returns realized over more recent time periods, investor return expectations and realizations converge. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. By ensuring that the risk premium study encompasses the longest possible period for which data are available, short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would be reluctant to invest money.

### C. ALLOWED RISK PREMIUMS

**Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE ELECTRIC UTILITY INDUSTRY.**

A. To estimate the electric utility industry's cost of common equity, I also examined the historical risk premiums implied in the ROEs allowed by regulatory commissions for electric utilities over the 1986-2010 period for which data were available, relative to the contemporaneous level of the long-term Treasury bond yield. This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, Risk Premium, CAPM, etc.) presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace. Historical allowed ROE data are readily available over long periods on a quarterly basis from Regulatory Research Associates (now SNL) and easily verifiable from SNL publications and past commission decision archives.

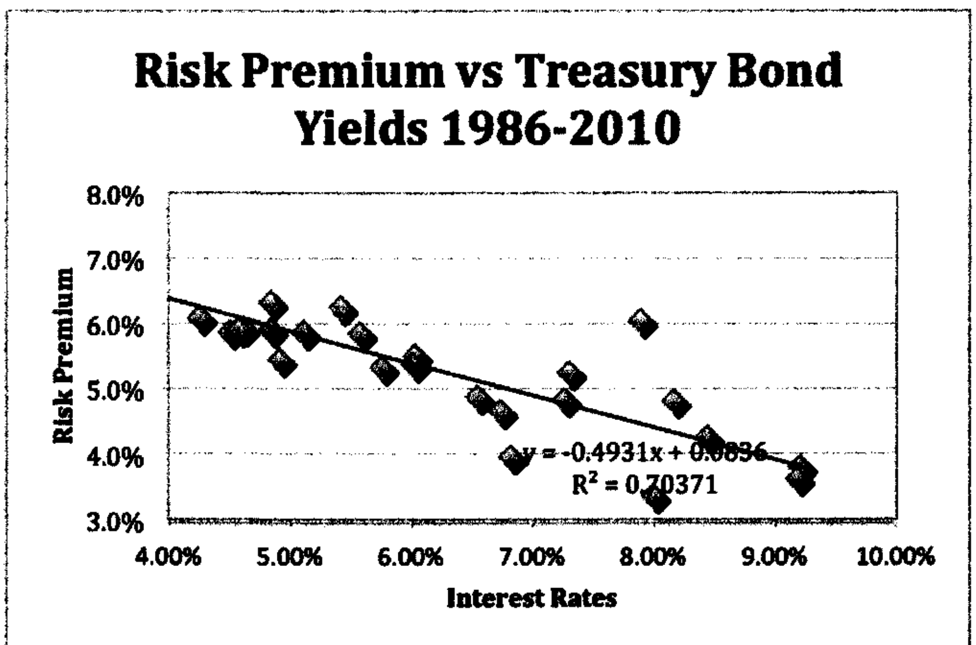
The average ROE spread over long-term Treasury yields was 5.3% over the entire 1986-2010 period for which data were available from SNL. The graph below shows the year-by-year allowed risk premium. The escalating trend of the risk premium in response to lower interest rates and rising competition is noteworthy.




A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the 1986-2010 period:

$$RP = 8.3600 - 0.4931 \text{ YIELD} \qquad R^2 = 0.70$$

The relationship is highly statistically significant[4] as indicated by the very high $R^2$. The graph below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.




Inserting the current long-term Treasury bond yield of 5.0% in the above equation suggests that a risk premium estimate of 5.9% should be allowed, implying a cost of equity of 10.9% and 11.2% inclusive of the flotation cost

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[4] The coefficient of determination $R^2$, sometimes called the "goodness of fit measure," is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher $R^2$ the higher is the degree of the overall fit of the estimated regression equation to the sample data. The t-statistic is a standard measure of the statistical significance of an independent variable in a regression relationship. A t-value above 2.0 is considered highly significant.

allowance. I note that the latter estimate is nearly identical to that obtained from the historical risk premium study of the utility industry.

**Q. DO INVESTORS TAKE INTO ACCOUNT ALLOWED RETURNS IN FORMULATING THEIR RETURN EXPECTATIONS?**

A. Yes, they do. Investors do take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value Line and SNL. Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless an important determinant of investor growth perceptions and investor expected returns.

**Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.**

A. The table below summarizes the ROE estimates obtained from the two risk premium studies.

| Risk Premium Method | ROE |
|---|---|
| Historical Risk Premium Electric | 11.0% |
| Allowed Risk Premium | 11.2% |

## D. DCF ESTIMATES

**Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.**

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the standard DCF model:

$$K_e = D_1/P_o + g$$

where: $K_e$ = investors' expected return on equity.

$D_1$ = expected dividend at the end of the coming year.

$P_o$ = current stock price.

$g$ = expected growth rate of dividends, earnings, stock price, book value.

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, $K_e$, can be viewed as the sum of an expected dividend yield, $D_1/P_o$, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer '$K_e$' from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, Regulatory Finance, and Chapter 8 of my latest textbook, The New Regulatory Finance. The standard DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The standard DCF model also assumes that dividends are paid at the end of each year when, in fact, dividend payments are normally made on a quarterly basis.

**Q. HOW DID YOU ESTIMATE DUKE ENERGY OHIO'S COST OF EQUITY WITH THE DCF MODEL?**

A. I applied the DCF model to two proxies for Duke Energy Ohio: (1) a group of investment-grade dividend-paying integrated electric utilities, and (2) a group consisting of the electric utility companies that make up S&P's Electric Utility Index. The proxy companies were required to have at least 50% of their revenues from regulated electric revenues.

In order to apply the DCF model, two components are required: the expected dividend yield ($D_1/P_o$) and the expected long-term growth (g). The expected dividend, $D_1$ in the annual DCF model, can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. This is because the current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the dividend yields reported in the March 2011 edition of Value Line Investment Analyzer (VLIA) software.

Basing dividend yields on average results from a large group of companies reduces the concern that the vagaries of individual company stock prices will result in an unrepresentative dividend yield.

**Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?**

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large and reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model.

Growth rate forecasts of analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. (Zacks). I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. The latter are also conveniently provided in the Value Line software. I also used Value Line's growth forecasts as additional proxies.

**Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL?**

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation for two reasons. First, historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore redundant. Second, published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts. This considerable literature is summarized in Chapter 9 of my most recent book, <u>The New Regulatory Finance</u>.

**Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH IN THE DCF MODEL?**

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, 'ROE', as follows:

$$g = b \times ROE$$

where: $g$ = expected growth rate in earnings/dividends

$b$ = expected retention ratio

ROE = expected return on book equity

**Q. DO YOU HAVE ANY RESERVATIONS IN REGARD TO THE SUSTAINABLE GROWTH METHOD?**

A. Yes, I do. First, the sustainable method of predicting growth is only accurate under the assumptions that the ROE is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Second, and more importantly, the sustainable growth method contains a logic trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Third, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore chose not to rely on this method.

**Q. DID YOU CONSIDER DIVIDEND GROWTH IN APPLYING THE DCF MODEL?**

A. No, not at this time. The reason is that as a practical matter, while there is an abundance of earnings growth forecasts, there are very few forecasts of dividend growth. Moreover, it is widely expected that some utilities will continue to lower their dividend payout ratio over the next several years in response to heightened business risk and the need to fund very large construction programs over the next decade. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks and finance large infrastructure investments. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in earnings that will support future dividends and share prices.

**Q. IS THERE EMPIRICAL EVIDENCE DOCUMENTING THE IMPORTANCE OF EARNINGS IN EVALUATING INVESTORS' EXPECTATIONS?**

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Zacks Investment, First Call Thompson, and Multex provide comprehensive compilations of investors' earnings forecasts, to name some. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, which account for 65% of the ranking.

**Q. DR. MORIN, HOW DID YOU APPROACH THE COMPOSITION OF COMPARABLE GROUPS IN ORDER TO ESTIMATE DUKE ENERGY OHIO'S GENERATION ASSETS' COST OF EQUITY WITH THE DCF METHOD?**

A. Because the common equity supporting Duke Energy Ohio's generation assets are not publicly traded, the DCF model cannot be applied to these assets and proxies must be used. There are two possible approaches in forming proxy groups of companies.

The first approach is to apply cost of capital estimation techniques to a select group of companies directly comparable in risk to Duke Energy Ohio's generation assets. Theoretically, these companies are chosen by the application of stringent screening criteria to a universe of electric utility stocks in an attempt to identify companies with the same investment risk as Duke Energy Ohio's generation assets. Examples of screening criteria include bond rating, beta risk, size, percentage of revenues from electric utility operations, and common equity ratio. In practice, there are very few, if any, such publicly-traded "pure-play" companies.

Moreover, Duke Energy Ohio faces unique market circumstances in the state of Ohio. Under current Ohio legislation, Duke Energy Ohio's electric generation is sold in a competitive market in Ohio, and its retail customers have the ability to switch to alternative suppliers for their electric generation service. Competitive retail electric suppliers can and do supply power to Duke Energy Ohio's current customers in Ohio, and the Company has experienced an increase in customer switching in the second half of 2009 and into 2010 and 2011. These evolving market conditions may continue to impact Duke Energy Ohio's results of operations. Increased competition resulting from deregulation or restructuring efforts in Ohio, coupled with the rules governing ESPs whereby every three to four years the Commission may alter a utility's standard service offer model, could continue to have a significant adverse impact on Duke Energy Ohio's financial position, results of operations or cash flow. The uniqueness of Duke Energy Ohio's regulatory model and market circumstances makes it almost impossible to identify a statistically viable sample of comparable companies for Duke Energy Ohio. Consequently, one must turn to the second approach to defining comparable companies.

The second approach is to apply cost of capital estimation techniques to a large group of electric utilities representative of the electric utility industry average and then make adjustments to account for any difference in investment risk between the subject assets, here Duke Energy Ohio's generation assets, and the industry average, if any such differences exist. In view of the extreme scarcity of pure plays for Duke of Ohio's generation assets, I have chosen the latter approach.

Moreover, in the current unstable industry environment, it is important to select relatively large sample sizes, as opposed to small sample sizes consisting of a handful of companies. This is because the electric utility industry capital market data is highly unstable at this time. As a result of this instability, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities.

From a statistical standpoint, confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Any distortions introduced by measurement errors in the two DCF components of equity return for individual companies, namely dividend yield and growth are mitigated. Utilizing a large portfolio of companies reduces the chance of either overestimating or underestimating the cost of equity for an individual company. For example, in a large group of companies, positive and negative deviations from the expected growth will tend to cancel out owing to the law of large numbers, provided that the errors are independent.[5] The average growth rate of several companies is less likely to diverge from expected growth than is the estimate of growth for a single firm. More generally, the assumptions of the DCF model are more likely to be fulfilled for a large group of companies than for any single firm or for a small group of companies.

**Q. CAN YOU DESCRIBE YOUR FIRST PROXY GROUP OF COMPANIES?**

A. Yes. As a first proxy for Duke Energy Ohio's generation business, I examined a group of investment-grade dividend-paying utilities designated as "integrated" utilities by S&P, meaning that these companies all possess electricity generation, distribution, and transmission assets. I began with all the companies designated as electric utilities by Value Line, that is, with Standard Industry Classification (SIC) codes 4911 to 4913. Foreign companies, private partnerships, private

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[5] If $\sigma_i^2$ represents the average variance of the errors in a group of N companies, and $\sigma_{ij}$ the average covariance between the errors, then the variance of the error for the group of N companies, $\sigma_N^2$ is:

$$\sigma_N^2 = \frac{1}{N}\bar{\sigma}_i^2 + \frac{N-1}{N}\bar{\sigma}_{ij}$$

If the errors are independent, the covariance between them ($\sigma_{ij}$) is zero, and the variance of the error for the group is reduced to:

$$\sigma_N^2 = \frac{1}{N}\sigma_i^2$$

As N gets progressively larger, the variance gets smaller and smaller.

companies, non dividend-paying companies, and companies below investment-grade, that is, companies with a Moody's bond rating below Baa3 as reported in AUS Utility Reports March 2011, were eliminated, as well as those companies whose market capitalization was less than $500 million in order to minimize any stock price anomalies due to thin trading. The group was further narrowed down to include only the parent companies of electric utilities designated as "integrated" by S&P, as is Duke Energy Ohio, in other words companies that include generation assets. The final group of 31 companies only includes those companies with at least 50% of their revenues from regulated electric utility operations. The same group was utilized earlier in connection with beta estimates and is retained for the DCF analysis.

I stress that this proxy group as well as the second group of proxy companies described below must be viewed as a portfolio of comparable risk. It would be inappropriate to select any particular company or subset of companies from these two groups and infer the cost of common equity from that company or subset alone.

**Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE INTEGRATED ELECTRIC UTILITY GROUP USING VALUE LINE GROWTH PROJECTIONS?**

A. Page 1 of Exhibit RAM-4 shows the raw dividend yield and growth data for the 31 companies while page 2 displays the DCF analysis. Ameren, Exelon, Edison, and FirstEnergy were eliminated on account of negative growth projections. PNM Resources was removed on account of its very high growth rate. As shown on Column 3, line 28 of page 2 of Exhibit RAM-4, the average long-term growth forecast obtained from Value Line is 6.1% for this group. Combining this growth rate with the average expected dividend yield of 4.7% shown in Column 4 produces an estimate of equity costs of 10.9% for the group shown in Column 5. Recognition of flotation costs brings the cost of equity estimate to 11.1%, shown in Column 6.

**Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE INTEGRATED ELECTRIC UTILITY GROUP USING THE ANALYSTS' CONSENSUS GROWTH FORECAST?**

A. From the original sample of 31 companies shown on page 1 of Exhibit RAM-5, DPL, Inc., was eliminated, as no analysts' growth forecasts were available from Zacks. Exelon was eliminated on account for its negative growth rate projection. For the remaining 29 companies shown on page 2 of Exhibit RAM-5, using the consensus analysts' earnings growth forecast published by Zacks of 6.1% instead of the Value Line forecast, the cost of equity for the group is 10.8%, unadjusted for flotation cost. Recognition of flotation costs brings the cost of equity estimate to 11.0%, shown in Column 6, line 31. This estimate is virtually identical to the previous estimate of 11.1% obtained from using Value Line's growth forecasts.

**Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE S&P UTILITY INDEX GROUP?**

A. Exhibit RAM-6, page 1 displays the electric utilities that make up S&P's Utility Index along with the input data for the DCF analysis. Page 2 of Exhibit RAM-6 displays the DCF analysis using Value Line growth projections. Ameren, Edison, Exelon, and First Energy were removed on account of their negative growth rates. As shown on column 2 of page 2 of Exhibit RAM-6, the average long-term growth forecast obtained from Value Line is 5.1% for this group. Coupling this growth rate with the average expected dividend yield of 4.9% shown in column 3 for each company produces an estimate of equity costs of 10.0% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of column 4 brings the cost of equity estimate to 10.2%, as shown in column 5. Removing the companies with less than 50% of their revenues from regulated electric operations, the average cost of equity is 10.5%, as shown on column 6.

Using the consensus analysts' growth forecast from Zacks instead of the Value Line growth forecast, the average cost of equity estimate for the group is 10.7%. Removing the companies with less than 50% of their revenues from regulated electric operations, the average cost of equity is 10.3%. This analysis is displayed on pages 1 and 2 of Exhibit MECO-1807.

**Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.**

A. The table below summarizes the DCF estimates:

| DCF STUDY | ROE |
|---|---|
| Integrated Electric Utilities Value Line Growth | 11.1% |
| Integrated Electric Utilities Zacks Growth | 11.0% |
| S&P Electric Utilities Value Line Growth | 10.5% |
| S&P Electric Utilities Zacks Growth | 10.3% |

## E. <u>NEED FOR FLOTATION COST ADJUSTMENT</u>

**Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.**

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that issuing common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (*e.g.*, printing, legal, prospectus). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix B to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation costs requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.53%.

According to the empirical finance literature discussed in Appendix B, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, as the argument goes, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plans, employees' savings plans, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated with and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

**Q. DR. MORIN, CAN YOU PLEASE ELABORATE ON THE MARKET PRESSURE COMPONENT OF FLOTATION COST?**

A. The indirect component, or market pressure component of flotation costs represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue, reflecting the basic economic fact that when the supply of securities is increased following a stock or bond issue, the price falls. The market pressure effect is real, tangible, measurable, and negative. According to the empirical finance literature the market pressure component of the flotation cost adjustment is approximately 1% of the gross proceeds of an issuance. The announcement of the sale of large blocks of stock produces a decline in a company's stock price, as one would expect given the increased supply of common stock.

**Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING SUBSIDIARY LIKE DUKE ENERGY OHIO THAT DOES NOT TRADE PUBLICLY?**

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its ultimate parent, in this case, Duke. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

## IV. SUMMARY OF COST OF EQUITY RECOMMENDATION

**Q. CAN YOU SUMMARIZE YOUR RESULTS AND RECOMENDATION?**

A. To arrive at my final recommendation, I performed four risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on historical and allowed risk premium data from utility industry aggregate data, using the current yield on long-term Treasury bonds. I also performed DCF analyses on two surrogates for Duke Energy Ohio's electric utility business: a group of investment-grade vertically integrated electric utilities and a group of electric utility companies that make up S&P's Electric Utility Index. The results are summarized in the table below.

| METHODOLOGY | ROE |
|---|---|
| Traditional CAPM | 10.1% |
| Empirical CAPM | 10.6% |
| Historical Risk Premium Electric | 11.0% |
| Allowed Risk Premium | 11.2% |
| DCF Integrated Electric Utilities Value Line Growth | 11.1% |
| DCF Integrated Electric Utilities Zacks Growth | 11.0% |
| DCF S&P Elec Utilities Value Line Growth | 10.5% |
| DCF S&P Elec Utilities Zacks Growth | 10.3% |

The results range from 10.1% to 11.2% with a midpoint of 10.7%. The average result is 10.7%. The median and truncated mean results are 10.8%.[6] I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in the above table must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from the summary table and infer the cost of common equity from that number alone.

**Q. HAVE YOU ADJUSTED THE COST OF EQUITY ESTIMATES TO ACCOUNT FOR THE FACT THAT DUKE ENERGY OHIO'S GENERATION BUSINESS IS RISKIER THAN THE AVERAGE ELECTRIC UTILITY?**

A. No, I did not. Although Duke Energy Ohio's generation business is riskier than

[6] The truncated mean is obtained by removing the low and high estimates and averaging the remaining estimates.

the average utility given the structure of the Ohio regulatory model, I did not make such an adjustment as part of my analysis. Duke Energy Ohio's plan is designed to provide long-term stability of price for its customers as well as a greater level of stability in its earnings for maintaining and committing its generation capacity to Ohio customers.

**Q. WHAT IS YOUR FINAL CONCLUSION REGARDING DUKE ENERGY OHIO'S COST OF COMMON EQUITY CAPITAL?**

A. Based on the above results of all my analyses and the application of my professional judgment, it is my opinion that a just and reasonable return on the common equity capital of Duke Energy Ohio at this time is 10.75%.

**Q. WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR RECOMMENDED RETURN ON DUKE ENERGY OHIO'S COMMON EQUITY CAPITAL?**

A. My recommended return on common equity for Duke Energy Ohio is predicated on the adoption of a certification period capital structure consisting of approximately 55% - 56% common equity capital. As discussed below, a stronger than average capital structure is required in order to offset the higher business risks experienced by the Company and the uncertainties regarding the regulatory regime to prevail in the state of Ohio over the next five years.

If the Commission imputes a capital structure consisting of substantially more or (less) debt than the Company's test year capital structure, the higher or (lower) common equity cost rate related to a changed common equity ratio should be reflected in the approach. If the Commission ascribes a capital structure different from the test year capital structure, which imputes a higher debt amount for example, the repercussions on equity costs must be recognized. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing. In other words, the greater the debt ratio, the greater is the return required by equity investors. Both the cost of incremental debt and the cost of equity must be adjusted to reflect the additional risk associated with the more debt-heavy capital structure. Lower common equity ratios imply greater risk and higher capital cost, and conversely.

Should the Commission decide to deviate from the capital structure, empirical finance literature demonstrates that with each reduction in common equity ratio of 1%, the return on equity increases by approximately 10 basis points, and conversely of course.

**Q. GIVEN THE COMPANY'S UNIQUE BUSINESS RISKS AND REGULATORY RISKS, IS THE COMPANY'S TEST YEAR CAPITAL STRUCTURE REASONABLE?**

A. Yes, it is. I have compared the Company's rate year capital structure with: 1) the capital structures adopted by regulators for electric utilities, and 2) the actual capital structures of comparable electric utilities.

The April 2011 edition of SNL Energy's (formerly Regulatory Research Associates) "*Regulatory Focus: Major Rate Case Decisions*" reports an average percentage of common equity in the adopted capital structure of 49% for electric utilities for 2010, which is slightly below the Company's 55% - 56% proposed common equity ratio in this case. The same is true for the actual capital structures of my comparable group of integrated electric utilities.

Although the Company's capital structure contains slightly less financial risk than its peers, a stronger capital structure than that of its peers is required in order to offset: 1) the unique business risks in the Ohio jurisdiction, 2) the regulatory risks with regards to the regime of regulation expected to prevail in Ohio over the next ten years, and 3) the risks associated with the proposed term of the Company's pricing plan in this case and the tenants of Ohio's regulatory structure. The Company's business risks associated with its generation assets exceed the industry average at this time. As discussed earlier, since the Company's electric security plan (ESP) was implemented in 2009, the Company has experienced customer losses and deteriorating financial results because of both low market prices in the generation market and greater competitive forces in Ohio. The continuing recessionary economy of Ohio, along with low power prices, exacerbates margin losses and customer switching. As I alluded to earlier, regulatory risks remain high as well since the terms of the regulatory compact in Ohio now include periodic price testing for Commission-approved ESPs that extend beyond three year terms and earnings caps on utilities.

**Q. WOULD YOU NOW DISCUSS THE IMPLICATIONS OF A STAYOUT PROVISION FOR THE ALLOWED ROE?**

A. The Company has informed me that it will be proposing an ESP that will cover nine years and five months. This exposes the Company to the risk that the cost of equity may go up during the course of the rate plan, without the Company having an opportunity to reset the allowed return to reflect such an increase. It seems likely that upward changes in interest rates may be more likely than downward changes. As more fully explained by Duke Energy Ohio witness William Don Wathen Jr, the Company's proposed non-bypassable capacity charge (Rider RC) is largely predicated upon costs to serve and a rate of return. It is further my understanding that under Ohio law that the Company's proposed ESP will be subject to Commission review and testing every four years. Over the long-term period of the ESP, the required ROE may change for a variety of factors including general economic conditions, changes in risk profiles, etc., and as such, it would be reasonable, in the context of the year four and year eight reviews, to ascertain whether any adjustment (increase or decrease) to the ROE rate is appropriate. As a result, and as supported by Mr. Wathen, the Company is proposing that Commission, any intervenor, or the Company may, at the time of the periodic review, offer testimony regarding changes to the ROE used for calculating Rider RC.

**Q. IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED TESTIMONY AND THE DATE ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?**

A. Perhaps. Capital market conditions are extremely volatile and uncertain at this time. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I would evaluate those changes and their impact on my testimony accordingly.

## V. CONCLUSION

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

# APPENDIX A
## CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by $R_F$ and the return on the market as a whole by $R_M$, the CAPM is:

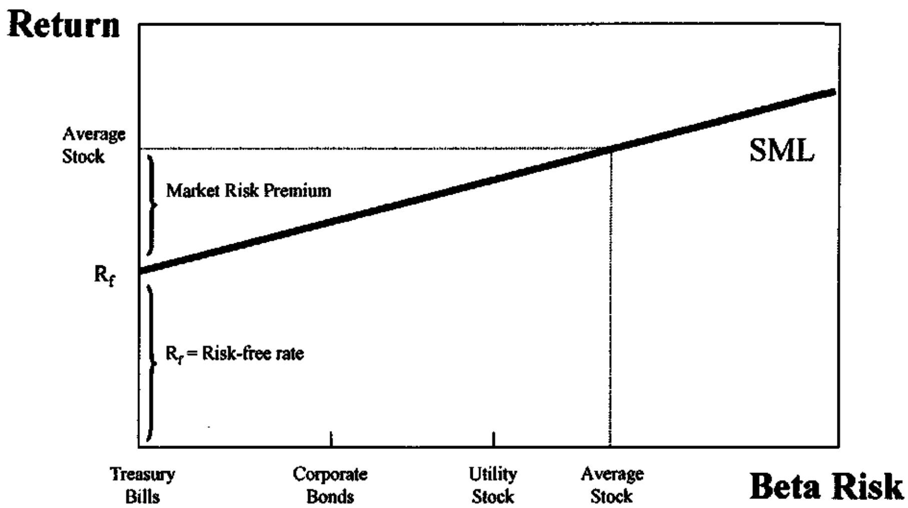
$$K = R_F + \beta(R_M - R_F) \tag{1}$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K, that could be gained on a risk-free investment, $R_F$, plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, $\beta$, and the market risk premium, $(R_M - R_F)$, where $R_M$ is the market return . The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

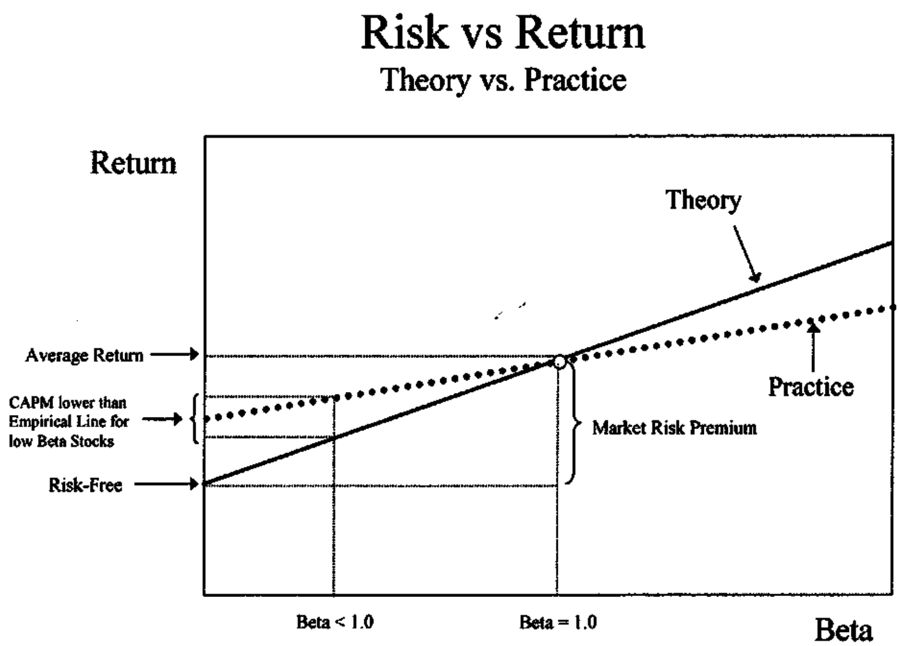
$$K = R_F + \beta \times MRP \tag{2}$$

The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.

CAPM and Risk - Return
in Capital Markets




A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].




A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (3)$$

where $\alpha$ is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \qquad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

**Theoretical Underpinnings**

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of "alpha" in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979) and Litzenberger et al. (1980) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, $R_Z$, replacing the risk-free rate, $R_F$. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

**Empirical Evidence**

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

| Empirical Evidence on the Alpha Factor | | |
|---|---|---|
| **Author** | **Range of alpha** | **Period relied** |
| Black (1993) | -3.6% to 3.6% | 1931-1991 |
| Black, Jensen and Scholes (1972) | -9.61% to 12.24% | 1931-1965 |
| Fama and McBeth (1972) | 4.08% to 9.36% | 1935-1968 |
| Fama and French (1992) | 10.08% to 13.56% | 1941-1990 |
| Litzenberger and Ramaswamy (1979) | 5.32% to 8.17% | |
| Litzenberger, Ramaswamy and Sosin (1980) | 1.63% to 5.04% | 1926-1978 |
| Pettengill, Sundaram and Mathur (1995) | 4.6% | |
| Morin (1994) | 2.0% | 1926-1984 |
| Harris, Marston, Mishra, and O'Brien (2003) | 2.0% | 1983-1998 |

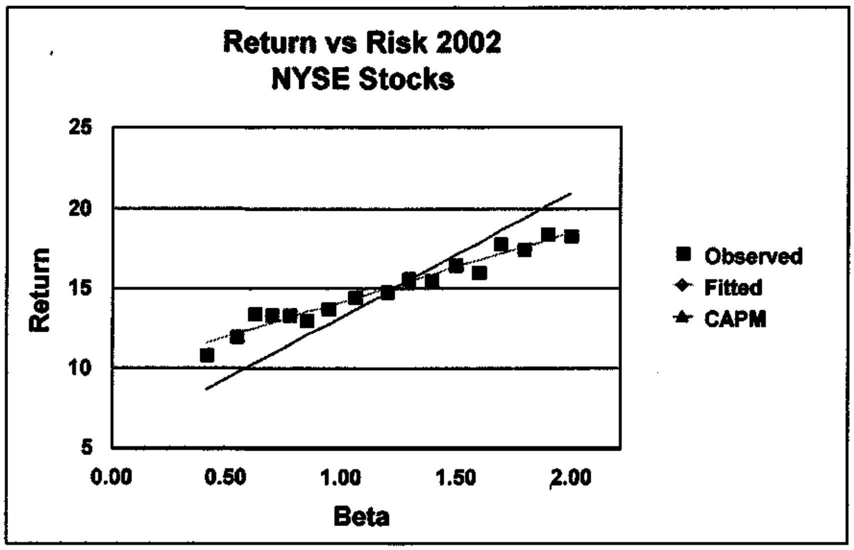
Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

$$K = .0829 + .0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6 percent, this relationship implies that the intercept of the risk-return relationship is higher than the 6 percent risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0 percent in that period, that is, the market risk premium $(R_M - R_F)$ = 8 percent, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2 percent, suggesting an alpha factor of 2 percent.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

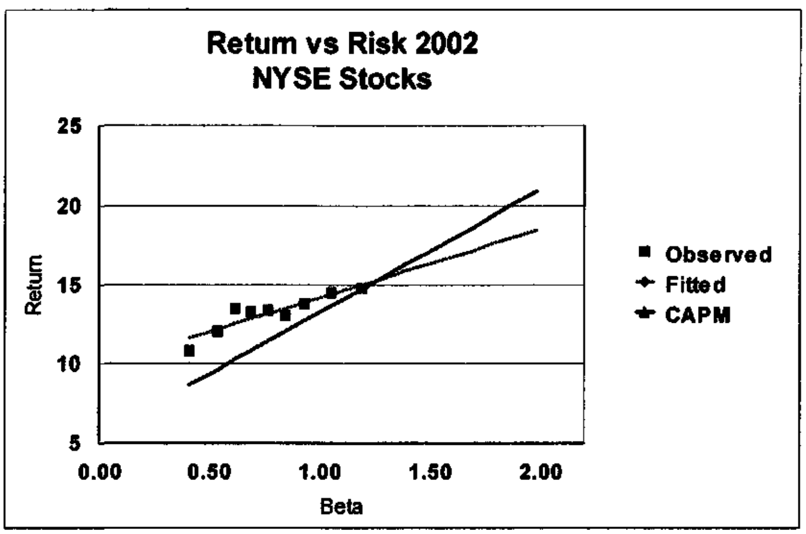
## CAPM vs ECAPM




Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return ("TSR") reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

| Portfolio # | Beta | Return |
|---|---|---|
| portfolio 1 | 0.41 | 10.87 |
| portfolio 2 | 0.54 | 12.02 |
| portfolio 3 | 0.62 | 13.50 |
| portfolio 4 | 0.69 | 13.30 |
| portfolio 5 | 0.77 | 13.39 |
| portfolio 6 | 0.85 | 13.07 |
| portfolio 7 | 0.94 | 13.75 |
| portfolio 8 | 1.06 | 14.53 |
| portfolio 9 | 1.19 | 14.78 |
| portfolio 10 | 1.48 | 20.78 |

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7 percent while the slope is less than equal to the market risk premium of 7.7 percent predicted by the plain vanilla CAPM for that period.




In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year U.S. Treasury Bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

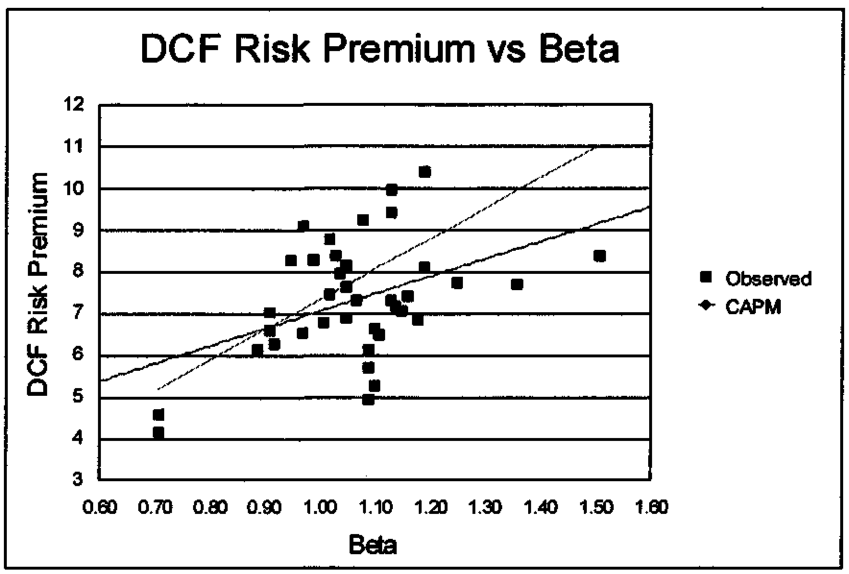
**Table A-1 Risk Premium and Beta Estimates by Industry**

| | Industry (1) | DCF Risk Premium (2) | Raw Industry Beta (3) | Adjusted Industry Beta (4) |
|---|---|---|---|---|
| 1 | Aero | 6.63 | 1.15 | 1.10 |
| 2 | Autos | 5.29 | 1.15 | 1.10 |
| 3 | Banks | 7.16 | 1.21 | 1.14 |
| 4 | Beer | 6.60 | 0.87 | 0.91 |
| 5 | BldMat | 6.84 | 1.27 | 1.18 |
| 6 | Books | 7.64 | 1.07 | 1.05 |
| 7 | Boxes | 8.39 | 1.04 | 1.03 |
| 8 | BusSv | 8.15 | 1.07 | 1.05 |
| 9 | Chems | 6.49 | 1.16 | 1.11 |
| 10 | Chips | 8.11 | 1.28 | 1.19 |
| 11 | Clths | 7.74 | 1.37 | 1.25 |
| 12 | Cnstr | 7.70 | 1.54 | 1.36 |
| 13 | Comps | 9.42 | 1.19 | 1.13 |
| 14 | Drugs | 8.29 | 0.99 | 0.99 |
| 15 | ElcEq | 6.89 | 1.08 | 1.05 |
| 16 | Energy | 6.29 | 0.88 | 0.92 |
| 17 | Fin | 8.38 | 1.76 | 1.51 |
| 18 | Food | 7.02 | 0.86 | 0.91 |
| 19 | Fun | 9.98 | 1.19 | 1.13 |
| 20 | Gold | 4.59 | 0.57 | 0.71 |
| 21 | Hlth | 10.40 | 1.29 | 1.19 |
| 22 | Hsld | 6.77 | 1.02 | 1.01 |
| 23 | Insur | 7.46 | 1.03 | 1.02 |
| 24 | LabEq | 7.31 | 1.10 | 1.07 |
| 25 | Mach | 7.32 | 1.20 | 1.13 |
| 26 | Meals | 7.98 | 1.06 | 1.04 |
| 27 | MedEq | 8.80 | 1.03 | 1.02 |
| 28 | Pap | 6.14 | 1.13 | 1.09 |
| 29 | PerSv | 9.12 | 0.95 | 0.97 |
| 30 | Retail | 9.27 | 1.12 | 1.08 |
| 31 | Rubber | 7.06 | 1.22 | 1.15 |

[1] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

| | | | | |
|---|---|---|---|---|
| 32 | Ships | 1.95 | 0.95 | 0.97 |
| 33 | Stee | 4.96 | 1.13 | 1.09 |
| 34 | Telc | 6.12 | 0.83 | 0.89 |
| 35 | Toys | 7.42 | 1.24 | 1.16 |
| 36 | Trans | 5.70 | 1.14 | 1.09 |
| 37 | Txtls | 6.52 | 0.95 | 0.97 |
| 38 | Util | 4.15 | 0.57 | 0.71 |
| 39 | Whlsl | 8.29 | 0.92 | 0.95 |
| | **MEAN** | **7.19** | | |

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:




If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2 percent, that is approximately equal to 25 percent of the expected market risk premium of 7.2 percent shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2 percent. Instead, the observed slope of close to 5 percent is approximately equal to 75 percent of the expected market risk premium of 7.2 percent, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

**Practical Implementation of the ECAPM**

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (5)$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP \qquad (6)$$

The empirical findings support values of $\alpha$ from approximately 2 percent to 7 percent. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2 percent - 3 percent is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM[2]. An alpha in the range of 1 percent - 2 percent is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5 percent, the MRP is 7 percent, and the alpha factor is 2 percent. The cost of capital is determined as follows:

$$K = R_F + \alpha + \beta\ (MRP - \alpha)$$
$$K = 5\% + 2\% + 0.80(7\% - 2\%)$$
$$= 11\%$$

[2] The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP$$

With an alpha of 2 percent, a MRP in the 6 percent - 8 percent range, the 'a" coefficient is 0.25, and the ECAPM becomes[3]:

$$K = R_F + 0.25\,MRP + 0.75\,\beta\,MRP$$

Returning to the numerical example, the utility's cost of capital is:

$$K = 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\%$$
$$= 11\%$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical[4].

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[3] Recall that alpha equals 'a' times MRP, that is, alpha = a MRP, and therefore a = alpha/MRP. If alpha is 2 percent, then a = 0.25

[4] In the Morin (1994) study, the value of "a" was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520\,\beta$$

The value of a that best explained the observed relationship was 0.25.

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# APPENDIX B

# FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

## 1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.-Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between \$60 and \$500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

## FLOTATION COSTS: RAISING EXTERNAL CAPITAL

(Percent of Total Capital Raised)

| Amount Raised in $ Millions | Average Flotation Cost: Common Stock | Average Flotation Cost: New Debt |
|---|---|---|
| $ 2 - 9. 99 | 13.28% | 4.39% |
| 10 - 19. 99 | 8.72 | 2.76 |
| 20 - 39. 99 | 6.93 | 2.42 |
| 40 - 59. 99 | 5.87 | 1.32 |
| 60 - 79. 99 | 5.18 | 2.34 |
| 80 - 99. 99 | 4.73 | 2.16 |
| 100 - 199. 99 | 4.22 | 2.31 |
| 200 - 499. 99 | 3.47 | 2.19 |
| 500 and Up | 3.15 | 1.64 |

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

## 2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_0 + g$$

If $P_0$ is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, $P_0$ equals $B_0$, the book value per share, then the company's required return is:

$$r = D_1/B_0 + g$$

Denoting the percentage flotation costs 'f', proceeds per share $B_0$ are related to market price $P_0$ as follows:

$$P - fP = B_0$$

$$P(1 - f) = B_0$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1-f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for $25, investors expect the firm to pay a dividend of $2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are $23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

## ASSUMPTIONS:

| | |
|---|---|
| ISSUE PRICE = | $25.00 |
| FLOTATION COST = | 5.00% |
| DIVIDEND YIELD = | 9.00% |
| GROWTH = | 5.00% |
| | |
| EQUITY RETURN = (D/P + g) | **14.00%** |
| ALLOWED RETURN ON EQUITY = (D/P(1-f) + g) | **14.47%** |

| Yr | COMMON STOCK (1) | RETAINED EARNINGS (2) | TOTAL EQUITY (3) | STOCK PRICE (4) | MARKET / BOOK RATIO (5) | EPS (6) | DPS (7) | PAYOUT (8) |
|---|---|---|---|---|---|---|---|---|
| -------- | -------- | -------- | -------- | -------- | -------- | -------- | -------- | -------- |
| 1 | $23.75 | $0.000 | $23.750 | $25.000 | 1.0526 | $3.438 | $2.250 | 65.45% |
| 2 | $23.75 | $1.188 | $24.938 | $26.250 | 1.0526 | $3.609 | $2.363 | 65.45% |
| 3 | $23.75 | $2.434 | $26.184 | $27.563 | 1.0526 | $3.790 | $2.481 | 65.45% |
| 4 | $23.75 | $3.744 | $27.494 | $28.941 | 1.0526 | $3.979 | $2.605 | 65.45% |
| 5 | $23.75 | $5.118 | $28.868 | $30.388 | 1.0526 | $4.178 | $2.735 | 65.45% |
| 6 | $23.75 | $6.562 | $30.312 | $31.907 | 1.0526 | $4.387 | $2.872 | 65.45% |
| 7 | $23.75 | $8.077 | $31.827 | $33.502 | 1.0526 | $4.607 | $3.015 | 65.45% |
| 8 | $23.75 | $9.669 | $33.419 | $35.178 | 1.0526 | $4.837 | $3.166 | 65.45% |
| 9 | $23.75 | $11.340 | $35.090 | $36.936 | 1.0526 | $5.079 | $3.324 | 65.45% |
| 10 | $23.75 | $13.094 | $36.844 | $38.783 | 1.0526 | $5.333 | $3.490 | 65.45% |
| | | | 5.00% | 5.00% | | 5.00% | 5.00% | |

| Yr | COMMON STOCK (1) | RETAINED EARNINGS (2) | TOTAL EQUITY (3) | STOCK PRICE (4) | MARKET/ BOOK RATIO (5) | EPS (6) | DPS (7) | PAYOUT (8) |
|---|---|---|---|---|---|---|---|---|
| ------ | -------- | -------- | -------- | -------- | -------- | -------- | -------- | -------- |
| 1 | $23.75 | $0.000 | $23.750 | $25.000 | 1.0526 | $3.325 | $2.250 | 67.67% |
| 2 | $23.75 | $1.075 | $24.825 | $26.132 | 1.0526 | $3.476 | $2.352 | 67.67% |
| 3 | $23.75 | $2.199 | $25.949 | $27.314 | 1.0526 | $3.633 | $2.458 | 67.67% |
| 4 | $23.75 | $3.373 | $27.123 | $28.551 | 1.0526 | $3.797 | $2.570 | 67.67% |
| 5 | $23.75 | $4.601 | $28.351 | $29.843 | 1.0526 | $3.969 | $2.686 | 67.67% |
| 6 | $23.75 | $5.884 | $29.634 | $31.194 | 1.0526 | $4.149 | $2.807 | 67.67% |
| 7 | $23.75 | $7.225 | $30.975 | $32.606 | 1.0526 | $4.337 | $2.935 | 67.67% |
| 8 | $23.75 | $8.627 | $32.377 | $34.082 | 1.0526 | $4.533 | $3.067 | 67.67% |
| 9 | $23.75 | $10.093 | $33.843 | $35.624 | 1.0526 | $4.738 | $3.206 | 67.67% |
| 10 | $23.75 | $11.625 | $35.375 | $37.237 | 1.0526 | $4.952 | $3.351 | 67.67% |
| | | | **4.53%** | **4.53%** | | **4.53%** | **4.53%** | |

# RESUME OF ROGER A. MORIN

**(Spring 2011)**

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Atlanta, GA 30303

**RANK**: Emeritus Professor of Finance

**HONORS**: Distinguished Professor of Finance for Regulated Industry,
Director Center for the Study of Regulated Industry,
Robinson College of Business, Georgia State University.

## EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.
- Master of Business Administration, McGill University, Montreal, Canada, 1969.
- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

## EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pennsylvania, 1972-3
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- Associate Professor, University of Montreal School of Business, 1976-1979.
- Professor of Finance, Georgia State University, 1979-2011
- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2009
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986
- Emeritus Professor of Finance, Georgia State University, 2007-11

## OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Member Board of Directors, Executive Visions Inc., 1985-2011
- Member Board of Directors, Oceanstone Inn & Cottages Resort 2011
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.
- Member Board of Directors, Hotel Equities, Inc., 2009-2011

## PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Allete

AmerenUE

American Water Works Company

Ameritech

Arkansas Western Gas

Baltimore Gas & Electric – Constellation Energy

Bangor Hydro-Electric

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Cascade Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co

Central Telephone

Central & South West Corp.

CH Energy

Chattanoogee Gas Company

Cincinnatti Gas & Electric

Cinergy Corp.

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Edison

Consolidated Natural Gas

Constellation Energy

Delmarva Power & Light Co

Deerpath Group

Detroit Edison Company

Duke Energy Indiana

Duke Energy Kentucky

Duke Energy Ohio

DTE Energy

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Emera

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

Entergy Gulf States, Inc.

Entergy Louisiana, Inc.

Entergy Mississippi Power

Entergy New Orleans, Inc.

First Energy

Florida Water Association

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California - Verizon

GTE Northwest Inc. - Verizon

GTE Service Corp. - Verizon

GTE Southwest Incorporated - Verizon

Gulf Power Company

Havasu Water Inc.

Hawaiian Electric Company

Hawaiian Elec & Light Co

Heater Utilities – Aqua - America

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

Manitoba Hydro

Maritime Telephone

Maui Electric Co.

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Missouri Gas Energy

Mountain Bell

National Grid PLC

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Market Hydro

New Tel Enterprises Ltd.

New York Telephone Co.

Niagara Mohawk Power Corp

Norfolk-Southern

Northeast Utilities

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power

Nova Scotia Utility and Review Board

NUI Corp.

NV Energy

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

PNM Resources

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Pepco Holdings

Potomac Electric Power Co.

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Public Service of New Hampshire

Public Service of New Mexico

Puget Sound Energy

Quebec Telephone

Regie de l'Energie du Quebec

Rockland Electric

Rochester Telephone

SNL Center for Financial Execution

San Diego Gas & Electric

SaskPower

Sierra Pacific Power Company

Source Gas

Southern Bell

Southern States Utilities

Southern Union Gas

South Central Bell

Sun City Water Company

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

TXU Corp

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

## MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar
- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2008:

  National Seminars:

  *Risk and Return on Capital Projects*
  *Cost of Capital for Regulated Utilities*
  *Capital Allocation for Utilities*
  *Alternative Regulatory Frameworks*
  *Utility Directors' Workshop*
  *Shareholder Value Creation for Utilities*
  *Fundamentals of Utility Finance in a Restructured Environment*
  *Contemporary Issues in Utility Finance*

- SNL Center for Financial Education. faculty member 2008-2011.
  National Seminars: *Essentials of Utility Finance*
- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994.

## EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Corporate Finance

Rate of Return

Capital Structure

Generic Cost of Capital

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

## REGULATORY BODIES

Alabama Public Service Commission

Alaska Regulatory Commission

Alberta Public Service Board

Arizona Corporation Commission

Arkansas Public Service Commission

British Columbia Board of Public Utilities